NORTH CENTRAL POWER STUDY

REPORT OF PHASE I
VOLUME II

OCTOBER 1971

NORTH CENTRAL POWER STUDY

Report of Phase I

Volume 2

Study of Mine-Mouth Thermal Powerplants with Extra-High-Voltage Transmission for Delivery of Power to Load Centers

Prepared Under the Direction of
Coordinating Committee
North Central Power Study

October 1971

Preface

The North Central Power Study was a coordinated undertaking of the supply entities in the North Central and Rocky Mountain areas of the United States. The reporting of the study is contained in two volumes. Volume I is a summary of the work and results of the various committees and task forces organized for the study. This volume, Volume II, gives the detailed data, criteria and history which supply the backup material for the summary report.

The material in this volume was duplicated as it was submitted by the various working committees with only minor changes where required for clarity. Although the format of the individual report may vary, the detailed information is available.

NORTH CENTRAL POWER STUDY

PHASE I - VOLUME II

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I. History

The history of events leading up to the publication of Phase I of the North Central Power Study is given in abbreviated notes of the major meetings which were held. The following material was taken from Study Progress Reports which were sent to all Coordinating Committee members when published. These notes will give the reader an insight of some of the discussions held and study changes made during the progress of the study.

Progress Report No. 1
North Central Power Study
September 18, 1970

This is the first progress report on the North Central Power Study. It is appropriate that the history of this activity be included at this time to bring everyone up to date. Each report hereafter will be a continuation of this one.

1. May 26 -- Omaha Meeting

Assistant Secretary of the Interior James R. Smith launched the North Central Power Study. At a meeting of top executives of major power supply utilities Assistant Secretary Smith outlined a plan to combine hydropeaking with major thermal plants utilizing the enormous coal resources in Montana, Wyoming, Colorado and North Dakota. This plan has many benefits to the country of which the major ones are:

1. Low-cost energy
2. Environmental advantages
3. Adequate power supply

He asked for full cooperation of the utilities and stated the Department would supply up to 50 percent of the manpower required as well as technical and professional guidance. He stressed the Government's role would be one of providing manpower and leadership - not to dominate the study.

He stated he would write the utilities and ask for a commitment to proceed with the study. The Assistant Secretary's letter would be followed by a letter from Reclamation asking the utilities to name someone from management to be on a Coordinating Committee which would supervise the study.

Bureau of Reclamation Commissioner Ellis Armstrong, who was unable to attend, sent a statement saying overall Reclamation responsibility for the study would be under Regional Director Harold Aldrich in Billings, Montana. James A. Bradley, Assistant Regional Director in Billings, was named Study Manager to be responsible for day-by-day supervision of the study. The Commissioner stated Reclamation would take a leadership role wholeheartedly in this most important project.

2. June 18, 1970 -- Denver -- Coordinating Committee Meeting

As a result of a letter from Reclamation Regional Director Aldrich, a meeting of the Coordinating Committee was held. The general framework of the study was outlined and the following action taken:

1. S. W. (Stan) Swanson was named Chairman of the Coordinating Committee

2. A Study Scope Committee was formed to draft study scope and general guidelines and appoint committee and task force members.

3. Study Manager Bradley was to write the utilities asking for names of technical personnel who could be available for committees and task forces. He was also to draft committee and task force guidelines for review by the Study Scope Committee.

Director Aldrich discussed the role Reclamation would play in supplying water to the coal area as well as developing hydropeaking sites.

3. August 13, 1970 -- Billings -- Ad Hoc Scope Committee

Study Scope and General Guidelines as well as the Committee and Task Force Guidelines were reviewed and agreement was reached to recommend them to the Coordinating Committee for adoption. It was decided that a permanent Steering Committee should be set up. Assignments of personnel offered by the participants were made to the working committees and task forces subject to approval of the Coordinating Committee.

4. August 14, 1970 -- Denver -- Municipal Meeting

One of the issues that came up from the study was how to obtain representation on the Coordinating Committee by the many municipals throughout the area. The municipals requested a meeting with Assistant Secretary Smith to discuss his thoughts on this issue. Such a meeting was held on August 14, 1970. Assistant Secretary Smith could not attend but sent a prepared statement asking the municipals to work out a method by which one or more highly respected representatives of the municipal segment could be represented on the Coordinating Committee. As a result of the August 14 meeting the municipals submitted a proposal to Smith which requested from 14 to 19 representatives.

5. September 2, 1970 -- Denver -- Coordinating Committee Meeting

Study Manager Jim Bradley reported on the August 14 meeting of municipal representatives and their desire to participate in the study. Mr. Bradley said that Assistant Secretary Smith and Alex Radin, General Manager, APPA, had the matter under discussion and would probably settle on five to eight representatives. The Coordinating Committee was to be advised when the issue was resolved.

Mr. Harold E. Aldrich, Regional Director for the Bureau of Reclamation, discussed parallel investigations with "fuel suppliers" concerning coal and water resources. Eight companies had water options from Boysen and Yellowtail reservoirs under contract. Nine companies had applications for water under consideration. Some like The Montana Power Company, Pacific Power and Light Company, and the Black Hills Power and Light Company are interested in both studies. In an effort to coordinate the studies the following motion was adopted:

> "The Steering Committee should meet with fuel suppliers to discuss study plans, goals and objectives, and to discuss methods of obtaining the required information from the fuel suppliers."

The Study Scope and General Guidelines and the Committee and Task Force Guidelines were approved.

Appointments to Committees and Task Forces were approved.

Announcement was made that Mr. James Bradley was transferring to Washington, D.C., to be Chief of the Power Division for the Bureau of Reclamation and would not be available as the Study Manager.

Mr. William F. Graham was confirmed by the Coordinating Committee to succeed Mr. Bradley.

Establishment of a permanent Steering Committee was confirmed.

Messrs. Graham and Swanson were asked to implement the agreement whereby the participants would agree to support the study costs based on equal sharing, not to exceed $50,000.

The organization chart for the study was approved.

6. September 14, 1970 -- Denver -- Steering Committee, Working Committees and Task Forces Meeting

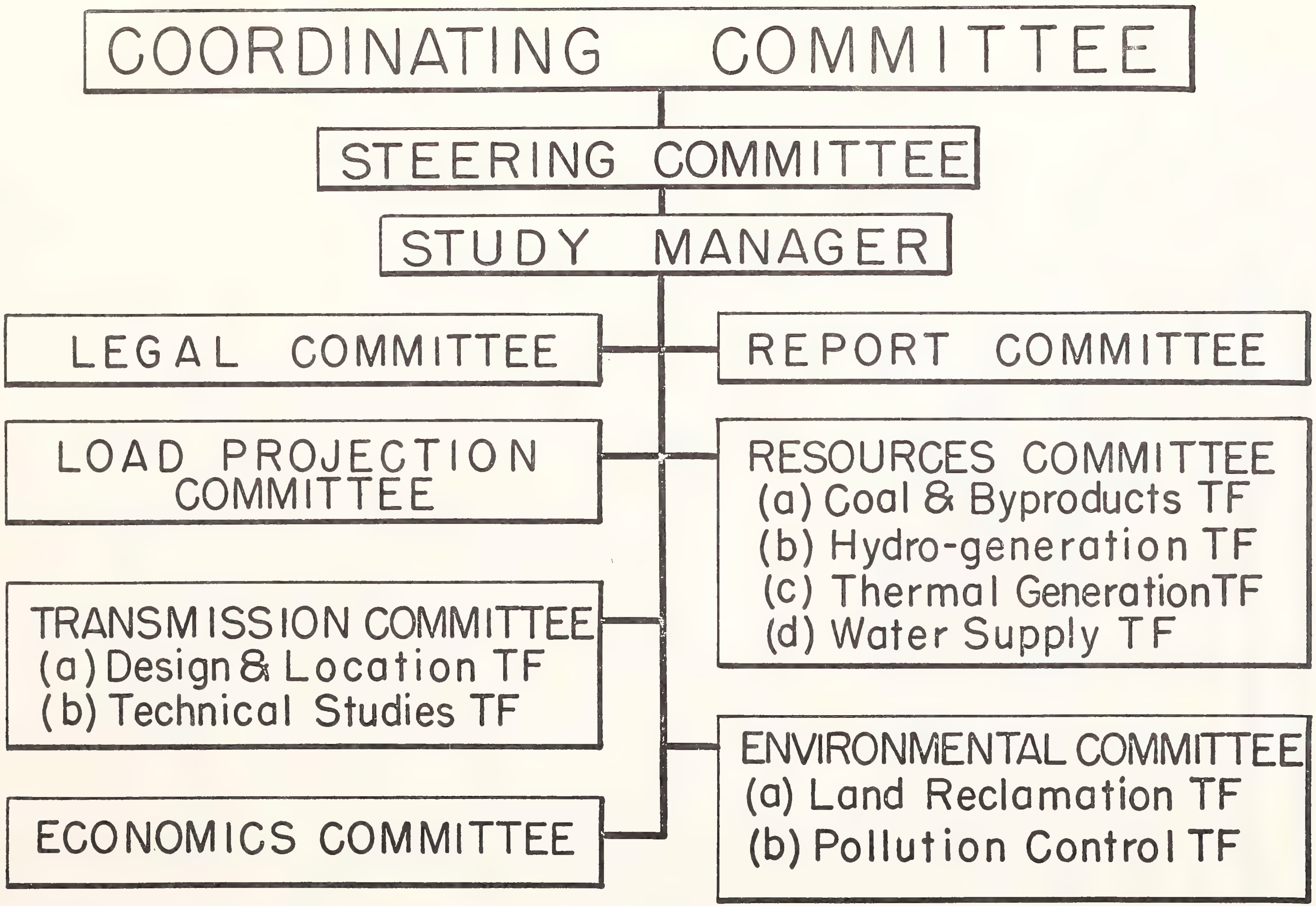
Chairman Stan Swanson introduced Bill Graham as Study Manager, replacing Jim Bradley. Mr. Graham reviewed the history of the North Central Power Study beginning with Assistant Secretary Smith's meeting in Omaha on May 26.

The Study Manager asked the working committees and task forces to follow the guidelines as they were basic to the study requirements. He asked to be advised in advance of committee and task force meetings. The Study Manager also asked for minutes of each meeting, copies of all correspondence, and a detail production schedule including detailed procedures. A flow chart to assist the committees may be prepared from the information received. Mr. Graham offered further suggestions as to some of the things expected of each working group. This was followed with discussions of various subjects to be covered for clarification of the job ahead. Ed Glass, NSP, pointed out that few items could be pinned down at this time and suggested that it would be necessary to "optimize by brute force" many of the items to be considered. There was also a question and answer period where the Steering Committee clarified many items for the committees.

Questions and problems that may come up as the study progresses are to be referred to Study Manager Bill Graham, or if he is not immediately available, given to L. W. Lloyd or C. R. Beitman in the same office.

Chairman Swanson stated the study was getting off to a good start and complimented the participating organizations for their cooperation.

Attached for information purposes are the organization chart, the Coordinating Committee, the Steering Committee, and a list of people assigned to the various committees and task forces.



TF = Task Force

Rev. 8-13-70

NORTH CENTRAL POWER STUDY
COORDINATING COMMITTEE
September 20, 1970

Stanley M. Swanson, Chairman	Iowa Public Service Company
H. E. Aldrich	Bureau of Reclamation
Robert Asheim	Black Hills Power and Light Company
George Beard	Pacific Power and Light Company
Robert F. Brewer	Iowa Southern Utilities Company
Harold H. Brown	Iowa Electric Light and Power Company
D. L. Bryner	Utah Power and Light Company
John J. Bugas	Colorado-Ute Electric Association, Inc.
Ed Glass	Northern States Power Company
James L. Grahl	Basin Electric Power Cooperative, Inc.
R.O.M. Grutle	Otter Tail Power Company
Glenn Hall	Idaho Power Company
David Kopecky	United Power Association
Frank Linder	Dairyland Power Cooperative
James R. Lyon	Iowa Power and Light Company
G. J. Lyshoj	Interstate Power Company
Richard B. Miller	Iowa-Illinois Gas and Electric Company
W. C. McCarthy	Kansas City Power and Light Company
H. N. McCoy	Union Electric Company
J. F. Rowe	Minnesota Power and Light Company
Mark Scarff	Montana-Dakota Utilities Co.
Don E. Schaufelberger	Nebraska Public Power District
A. D. Schmidt	Northwestern Public Service Company
Ralph W. Shaw	Omaha Public Power District
W. W. Talbott	The Montana Power Company
R. F. Walker	Public Service Company of Colorado

STEERING COMMITTEE
September 20, 1970

Stanley M. Swanson, Chairman	Iowa Public Service Company
D. L. Bryner	Utah Power and Light Company
John J. Bugas	Colorado-Ute Electric Association, Inc.
Ed Glass	Northern States Power Company
William F. Graham	Bureau of Reclamation
Ralph W. Shaw	Omaha Public Power District

STUDY MANAGER

William F. Graham	Bureau of Reclamation

September 22, 1970

NORTH CENTRAL POWER STUDY
COMMITTEES AND TASK FORCES

STEERING COMMITTEE

Stanley M. Swanson, Chairman, Iowa Public Service Company
William F. Graham, Bureau of Reclamation
James L. Grahl, Basin Electric Power Cooperative, Inc.
Ed C. Glass, Northern States Power Company
John J. Bugas, Colorado-Ute Association
Ralph W. Shaw, Omaha Public Power District
Dean L. Bryner, Utah Power and Light Company

STUDY MANAGER - William F. Graham

LEGAL COMMITTEE

Richard D. Wilson, Chairman, Nebraska Public Power District
William H. Wisdom, Basin Electric Power Cooperative, Inc.
Ernest J. London, Bureau of Reclamation
Alvin E. Bielefeld, Bureau of Reclamation
Arland D. Brusven, Northern States Power Company

LOAD PROJECTION COMMITTEE

Virge J. Dixon, Chairman, Bureau of Reclamation
Larry Stark, Public Service Company of Colorado
Howard F. Easton, Basin Electric Power Cooperative, Inc.
Lester Larson, Interstate Power Company

TRANSMISSION COMMITTEE

Harvey D. Hunkins, Chairman, Bureau of Reclamation
Glenn F. Walkup, Iowa Power and Light Company
Joe McKay, Pacific Power and Light Company
Charles A. Cabral, Bureau of Reclamation

TRANSMISSION - DESIGN AND LOCATION TASK FORCE

Charles A. Cabral, Chairman, Bureau of Reclamation
Joe McKay, Pacific Power and Light Company
R. K. Harbour, Iowa Southern Utilities Company
William K. Graw, Colorado-Ute Association
Stan Fallick, Nebraska Public Power District

TRANSMISSION - TECHNICAL STUDIES TASK FORCE

Glenn F. Walkup, Chairman, Iowa Power and Light Company
Ted Humann, Basin Electric Power Cooperative, Inc.
G. G. Worner, Northern States Power Company
Erwin W. Eggleston, Bureau of Reclamation
Clark L. Rose, Bureau of Reclamation
Wallace M. Ness, Otter Tail Power Company

ECONOMICS COMMITTEE

Leon R. Barrett, Chairman, Northern States Power Company
Richard W. Grant, Basin Electric Power Cooperative, Inc.
Louis C. Rassmussen, Kansas City Power and Light Company
Edward L. Leland, Bureau of Reclamation

REPORT COMMITTEE

Lester W. Lloyd, Chairman, Bureau of Reclamation
James R. Forest, Northern States Power Company
John E. Droubay, Utah Power and Light Company
Robert O. Marritz, Basin Electric Power Cooperative, Inc.

ENVIRONMENTAL COMMITTEE

George C. Paraskeva, Chairman, Basin Electric Power Cooperative, Inc.
Robert H. Madsen, Bureau of Reclamation
Gerald G. Bachman, Omaha Public Power District
Tom Gwynn, Montana-Dakota Utilities Co.

ENVIRONMENTAL - LAND RECLAMATION TASK FORCE

Tom Gwynn, Chairman, Montana-Dakota Utilities Co.
Dan T. Berube, The Montana Power Company
Dwight A. Covington, Bureau of Reclamation, Denver
Leroy E. Holmes, Bureau of Reclamation, Salt Lake City

ENVIRONMENTAL - POLLUTION CONTROL TASK FORCE

Gerald G. Bachman, Chairman, Omaha Public Power District
Kent E. Janssen, Basin Electric Power Cooperative, Inc.
Warren S. Kane, Iowa Public Service Company
Robert H. Madsen, Bureau of Reclamation

RESOURCES COMMITTEE

Howard N. Ericksen, Chairman, Nebraska Public Power District
W. H. Blankmeyer, The Montana Power Company
Phil Q. Gibbs, Bureau of Reclamation
Thomas L. Weaver, Bureau of Reclamation
William S. Landers, Public Service Company of Colorado

RESOURCES - COAL AND BYPRODUCTS TASK FORCE

William S. Landers, Chairman, Public Service Company of Colorado
Herman K. Dupree, Bureau of Reclamation
Lloyd A. Ernst, Basin Electric Power Cooperative, Inc.
A. Howard Smith, Office of Coal Research
Donald R. Thomson, Omaha Public Power District

RESOURCES - HYDRO-GENERATION TASK FORCE

Thomas L. Weaver, Chairman, Bureau of Reclamation
Creighton W. Bicket, Corps of Engineers
Gerald B. Cookson, Bureau of Reclamation
Robert J. Marchetti, Minnesota Power and Light Company

RESOURCES - THERMAL GENERATION TASK FORCE

W. H. Blankmeyer, Chairman, The Montana Power Company
George R. Hobbs, Colorado-Ute Association
Tom Christensen, Iowa-Illinois Gas and Electric Company
James Morgan, Pacific Power and Light Company

RESOURCES - WATER SUPPLY TASK FORCE

Phil Q. Gibbs, Chairman, Bureau of Reclamation
Harry L. Baker, Bureau of Reclamation
Gary B. Staley, Corps of Engineers
Jesse L. Honnold, Bureau of Reclamation
Wayne Stufft, Corps of Engineers

Notes
Fuel Supplier-Steering Committee Meeting
North Central Power Study
Albany Hotel, Denver, Colorado
October 14, 1970

The meeting was called to order at 9:30 a.m., October 14, 1970, by Mr. Harold E. Aldrich, Regional Director, Bureau of Reclamation, Billings, Montana. (Attendance list is attached.)

One of the purposes of the meeting was for the Bureau to provide estimated costs for delivery of water to several selected areas for future industrial development.

Mr. Phil Q. Gibbs, of the Bureau of Reclamation, gave a resume of the aqueduct studies accomplished over the past year and the approximate cost of water along the St. Xavier to Gillette aqueduct under various considerations of size. Cost of water at Colstrip was given with certain reservations related to the amount of cost included for off-stream storage. A copy of remarks by Mr. Gibbs and a map for orientation purposes is attached.

Following the coffee break, Bill Graham, Study Manager, North Central Power Study, gave a brief resume of the background of the North Central Power Study, what its objectives were, and an explanation of the relationship of the energy companies to the North Central Power Study.

Mr. Graham said that on May 26 Assistant Secretary James R. Smith launched the North Central Power Study. At a meeting of top executives of the major power suppliers at Omaha, Nebraska, a plan was outlined to combine hydropeaking with major thermal plants utilizing the enormous coal resources in Montana, Wyoming, Colorado, and North Dakota. Major benefits of the proposed plan include:

1. Low-cost energy.
2. Environmental advantages.
3. An adequate power supply.

The Assistant Secretary visualized large thermal and hydroplants in the Rocky Mountain area in the order of 20 to 70 million kilowatts of total installation with 345- to 765-kv transmission lines feeding load centers as far away as Minnesota, Missouri, Colorado, Utah and Idaho. These thermal plants in combination with oil and gas processing plants would make quite a large development in the coalfield area.

He asked for full cooperation of the utilities and stated the Department of the Interior would supply 50 percent of the manpower required as well as technical and professional guidance. He stressed the Government's role would be one of providing manpower and leadership - not to dominate the study.

The Assistant Secretary wrote the utilities asking for a commitment to proceed with the study. His letter was followed by one from the Bureau asking the utilities to name someone from management to be on a Coordinating Committee which would supervise the study.

The Bureau of Reclamation was given overall Federal responsibility for the study and the assignment was made to Regional Director Harold Aldrich in Billings, Montana.

Much progress has been made since the May 26 meeting. Mr. William F. Graham then discussed the organization setup for the study. (Copy of the organization chart is attached.)

There are presently 26 members of the Coordinating Committee with 9 more applications pending. (These were confirmed by the Coordinating Committee the following day.) There are 37 other Committee members and 37 Task Force members. All committees and working groups are staffed with experienced personnel drawn directly from the participating utilities.

Mr. Graham explained that general guidelines had been set up for both the overall study as well as for each individual committee and task force. The guidelines are general and flexible to meet new situations as they arise. Each working group is to prepare its own basic data for the period 1980 through 2000. The objective is to obtain delivered cost of power to load centers for various stages of development. The schedule calls for a report in about 1 year.

Mr. Graham explained that there were three steps that must be taken before construction starts:

(a) Completion of the study and its report which is to give costs of delivered power for various steps of say 5, 10, 15, 20-million kw developments.

(b) Determine how much power each entity wants and when.

(c) Determine practical development size and implementation for construction.

The Committees and Task Forces began work on September 14 and have been doing a wonderful job, the Study Manager reported.

The Committees and Task Forces need information from the energy companies to proceed with their assignments.

Mr. Graham said that most of the energy companies either own or have coal deposits under lease and some have options under contract with the Bureau of Reclamation for water from Boysen or Yellowtail Reservoirs.

Some participants in the North Central Power Study are participants in fuel supply studies also. Participants in the North Central Power Study are interested in the economical production of electric power from coal. They will need cooling water for the coal-fired thermal powerplants. There will probably be byproducts from conversion plants which could be useful in the production of electrical power and energy.

The Steering Committee of the NCPS believes it is most important to work closely with the fuel suppliers for economies and early development of the resources. By joint participation, savings in water and fuel costs can be accomplished; byproduct consumption by powerplants can be mutually beneficial; savings can be made in collective establishment of new towns, roads, as well as other such items; and he said we can all work together to solve the many environmental problems associated with such a development.

The following general information is needed:

1. Size, location, and type of coalfields (can be approximate).

2. Cost of fuel (cents per million BTU) at the various sites.

3. Processing plants contemplated which have a bearing on power supply. Include dates of construction, byproducts that can be used for fuel (amount, cost per million BTU), water requirements (possible joint use of water), and other possible mutual use factors.

The question was then asked "How can NCPS get the information?" There are several ways we could go; for instance, (1) A committee could be appointed to work with the NCPS Steering Committee, (2) The Resources Committee could go directly to each fuel supplier individually, (3) A form letter could be sent to each individually asking for data, or (4) Some other method could be devised.

Mr. George Fumich, Jr., Office of Coal Research, in commenting on coal processing plants, said that one relevant factor will be the timing of possible commercialization of research developments being pushed for coal conversion. Another factor is the priority in the conversion area. The technology and the type of project being developed will determine the major product and byproducts. In most processes gasification technology would mean less char available for power generation. Some processes that could be developed in the liquefaction area could mean sizeable amounts of char as a byproduct.

It was Mr. Fumich's opinion that gasification technology has the best chance of commercialization by the late '70's. The present funding will provide a reasonable chance to meet this target.

Because of the recent North Slope developments and other factors, Mr. Fumich thought that liquefaction will not be developed as quickly as gasification. The one exception is the FMC COED Project. However, he did not consider a target of low sulfur liquid fuels from coal to be in this category. He felt that clean energy from coal, regardless of whether it is a solid, liquid, or gas, should be developed as quickly as possible. Fumich would not try to forecast a time target in the low sulfur liquid fuel area because developing the technology depends on the level of funding.

The FMC COED Project dedicated recently, if successful, would produce liquids, char, gas, and chemicals from coal and would be a good basis for one of the energy centers being discussed. Fumich felt that liquids or gas could be produced equally well in the western sector using this process. Sizeable amounts of char would be produced and would fit in with the electric power developments being considered.

There was considerable discussion as to how the information and data on coal deposits, locations, size of reserves and the cost per million BTU's could be obtained from them for the various interests. Because of possible legal complications (antitrust legislation) and the individual companies' competitive positions, there was reluctance to give this information to the Steering Committee. The energy companies were advised that such data would not be maintained confidential by the North Central Power Study committees. A method was worked out, however, to submit the data to Mr. Joe Smith of the Bureau of Mines for processing. This data would be treated confidentially by the Bureau of Mines, combined so individual identity was lost, and then the data would be furnished to the Coal and Byproducts Task Force. Mr. Joe Smith, Bureau of Mines, said they would check back with the suppliers of confidential data before passing such information out.

There was some discussion on the feasibility of transmission of energy by wire vs. pipeline or rail. One point raised concerning reliability of electrical transmission was the number of outages on the EHV d.c. lines on the west coast during the first year's operation. Mr. Graham said that reliability was now being studied by one of the working committees.

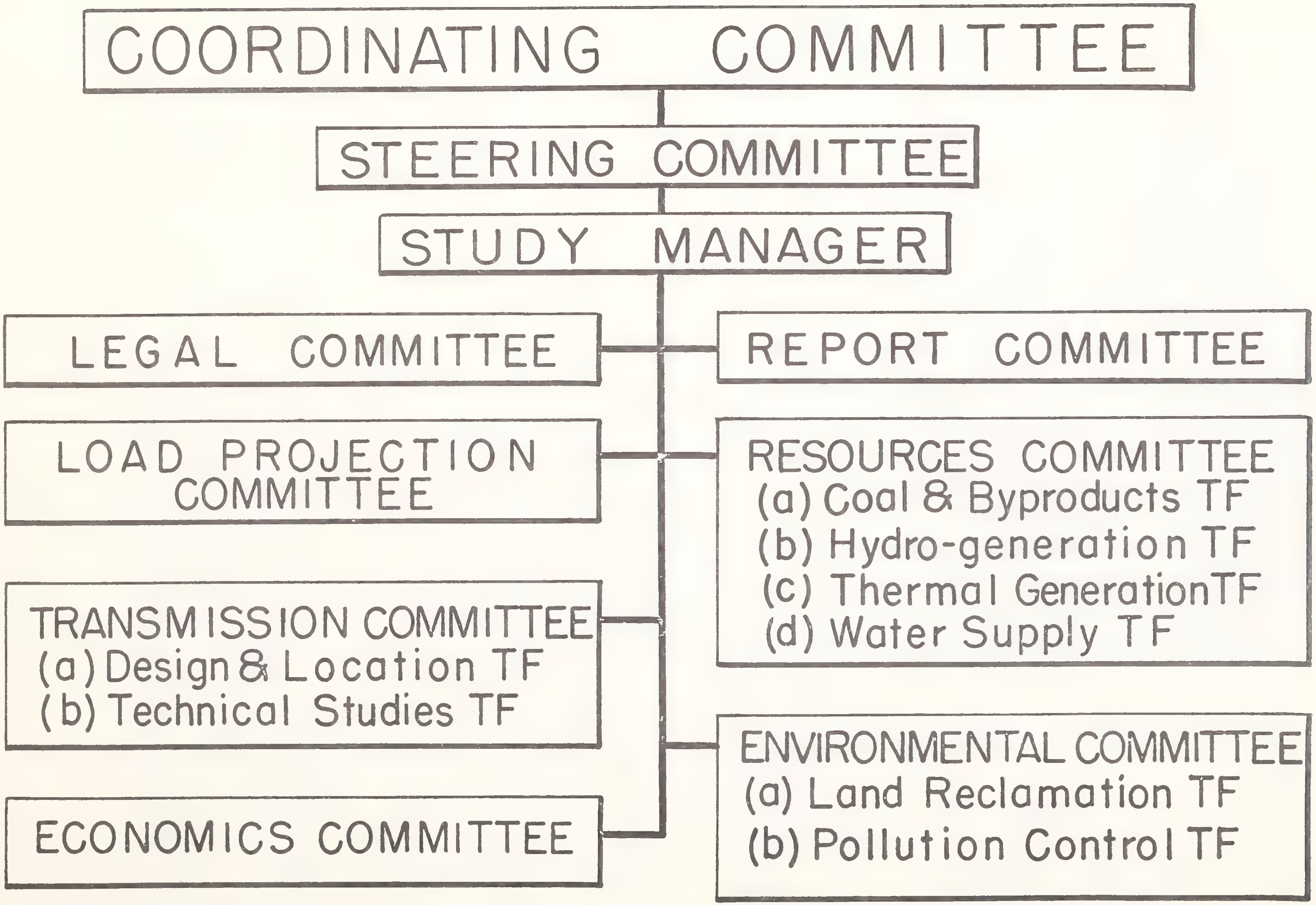
Phil Gibbs requested the locations of powerplants, petro-chemical plants and the quantity of water needed for each so that he could compute the cost of water. Comments from the floor indicated that for the Power Study, cost of water at the center of each county was adequate.

Joe Smith, Bureau of Mines, reported that there was good data on coal in Wyoming and North Dakota. Information on Montana coal was not quite ready. The Bureau of Mines will provide sufficient information on coal deposits from data to be submitted by the coal companies and from what it now has to permit the location of power generating stations.

Attendance
North Central Power Studies
Joint Meeting
Steering Committee & Fuel Suppliers, etc.
Albany Hotel, Denver, Colorado
October 14, 1970

Name	Company Affiliation
Myron Goodson	Dept. of Economic Planning & Development, Cheyenne, Wyoming
Dave Wilde	U.S. Bureau of Reclamation, Cheyenne, Wyoming
J. D. Brunk	Dept. of Economic Planning & Development, Cheyenne, Wyoming
R. E. Dillon	Panhandle Eastern P.L. Co., P.O. Box 1642, Houston, Texas
E. M. Self	Panhandle Eastern P.L. Co., Houston, Texas
Jack R. Gage	Wyoming Attorney General's Office, Cheyenne, Wyoming
Doyl M. Fritz	Wyoming Water Planning Program, Cheyenne, Wyoming
Jesse J. Jacobsen	Consolidation Coal Co., Denver, Colorado
Don Gasper	Consolidation Coal Co., Pittsburgh, Pennsylvania
Howard Arnett	Pacific Power & Light Company, Casper, Wyoming
Bob Asheim	Black Hills Power & Light Co., Rapid City, So. Dakota
Jim Hope	The Carter Oil Company, Houston, Texas
Don Geiger	The Carter Oil Company, Houston, Texas
Joe B. Smith	U.S. Bureau of Mines, Denver, Colorado
David J. Kull	Farmers Union Central Exchange, Laurel, Montana
T. L. Kirby	Shell Oil Co., 1700 Broadway, Denver, Colorado
E. C. Hixson, Jr.	Mobil Oil Corp., Denver, Colorado
Jess Maloney	Ayrshire Coal Co., Minneapolis, Minnesota
John Bugas	Colorado-Ute Electric Assn., Montrose, Colorado
Erhan Gilman	Colorado Interstate Gas Co., Colorado Springs, Colo.
Claude Van Dyke	Colorado Interstate Gas Co., Colorado Springs, Colo.
E. B. Griffith	U.S. Bureau of Reclamation, Denver, Colorado
H. Walter Anderson	U.S. Bureau of Reclamation, Denver, Colorado
Raoul E. Thibault	U.S. Bureau of Reclamation, Denver, Colorado
Don Breiby	Montana Water Resources Board, Helena, Montana
R. G. Mallander	Shell Oil Company, Denver, Colorado
Jim Fisher	P&M Coal Mining Co., Denver, Colorado
Charles Spielman	P&M Coal Mining Co., Denver, Colorado
Emil Lindseth	Gulf Mineral Resources Co., Denver, Colorado
Jack Rogers	Atlantic Richfield Company, Denver, Colorado
F. H. Persse	U.S. Bureau of Mines, Denver, Colorado
David Willard	U.S. Bureau of Mines, Denver, Colorado
R. A. Bovaird	Wyoming REA's, Wheatland, Wyoming
George Fumich, Jr.	Office of Coal Research, Interior Dept., Washington, D.C
Bob Marritz	Missouri Basin Systems Group, Denver, Colorado
Arthur L. Brown	Shell Oil Company, Denver, Colorado

Name	Company Affiliation
J. C. Finley	Kerr-McGee Corp., Oklahoma City, Oklahoma
R. L. Duncan	Kerr-McGee Corp., Oklahoma City, Oklahoma
Ed Glass	Northern States Power Co., Minneapolis, Minnesota
Ralph W. Shaw	Omaha Public Power District, Omaha, Nebraska
Bill Graham	U.S. Bureau of Reclamation, Billings, Montana
D. L. Bryner	Utah Power & Light Co., Salt Lake City, Utah
Roger A. Hofacker	The Montana Power Company, Butte, Montana
(Rep. W. P. Schmechel	Western Energy Co.)
Otto Shelton	Peabody Coal Co., Minneapolis, Minnesota
Richard E. Miller	Peabody Coal Co., St. Louis, Missouri
Phil Q. Gibbs	U.S. Bureau of Reclamation, Billings, Montana
F. K. Kennedy	Northern Natural Gas Co., Omaha, Nebraska
Thomas C. Woodward	Jenkins & Woodward, Coal Exploration, Casper, Wyoming
G. R. Hanson	U.S. Bureau of Reclamation, Great Falls, Montana
W. H. Taylor	U.S. Bureau of Reclamation, Denver, Colorado



TF = Task Force

Rev. 8-13-70

Progress Report No. 2
North Central Power Study
November 4, 1970

This is a continuation of Progress Report No. 1, dated September 18, 1970.

7. October 14, 1970 -- Fuel Supplier-Steering Committee Meeting

The meeting was chaired by Mr. Harold E. Aldrich, Regional Director, Bureau of Reclamation, Billings, Montana.

The purpose of the meeting was (a) to review the status of the pipeline and water studies of the Bureau of Reclamation, (b) to acquaint the fuel suppliers with the North Central Power Study, and (c) to determine how the Steering Committee could obtain required information from the fuel suppliers.

Mr. Phil Q. Gibbs of the Bureau of Reclamation gave a resume of the aqueduct studies accomplished over the past year including the approximate cost of water along the St. Xavier to Gillette aqueduct for various sizes. The cost of water at Colstrip was given with certain reservations related to the amount of cost included for offstream storage. The estimates together with a map are attached. Cost estimates for other water delivery points will be available in 3 or 4 months.

Bill Graham, Study Manager, North Central Power Study, reviewed briefly the background of the North Central Power Study, explained the objectives of the study and the relationship of the fuel suppliers to the North Central Power Study.

Some study participants own or hold leases on large coal deposits and are interested in early development as well as the economical generation of electric power from coal. Cooling water will be needed for the thermal powerplants. There could be some useful byproducts from coal processing plants that could be used in the thermal powerplants.

The Steering Committee of the North Central Power Study should work closely with the fuel suppliers for early economic development of the resources. By joint participation, savings in water and fuel costs can be realized; byproducts may be used by powerplants for mutual benefits; other savings may result from the collective establishment of new towns, roads, and similar items. The Study Manager recommended that they coordinate planning and work together to solve the many environmental problems associated with such a development.

The working committees and task forces need the following general information:

a. Size, location, and type of coalfields.

b. Cost of fuel in cents per million BTU's at various locations.

c. Coal processing plants under consideration which have a bearing on power supply. The Steering Committee would like to know dates of construction, byproducts that can be used for fuel (amount, cost per million BTU's), water requirements (possible joint use of water), and other possible mutual use factors.

It was mentioned that the development of petro-chemical products will probably be slow because of the impact of oil discovery on Alaska's North Slope. Gasification may come earlier than first anticipated--possibly by 1977. Availability and quantity of byproducts is unknown at present.

The question was asked, "How can the North Central Power Study get the information?" Several ways were suggested: (1) A committee could be appointed to work with the NCPS Steering Committee; (2) the Resources Committee could go directly to each fuel supplier individually; (3) a form letter could be sent to each asking for data; or (4) some other method could be devised.

It was concluded that the fuel supply companies would furnish information as to location, size of reserves, and cost per million BTU's to Mr. Joe Smith, Bureau of Mines, Denver, who will keep the information confidential. The Coal and Byproducts Task Force will get the data from the Bureau of Mines in a form that can be fed into the NCPS. Company ownerships will not be identified. To keep ownerships anonymous, mine locations will be given as near centers of counties.

8. October 15, 1970 -- <u>Steering Committee Meeting</u>

The Steering Committee agreed to recommend to the Coordinating Committee: (1) Approval of eight municipal representatives (submitted by Alex Radin, General Manager, American Public Power Association) and Neil Adams, Associated Electric Cooperative, Springfield, Missouri; (2) that Stan Swanson should handle press releases pertaining to the study; (3) that Mr. Joe B. Smith, Bureau of Mines, be on the Coal and Byproducts Task Force; and (4) use of 1970 prices and preparation of estimates for 1975 together with index figures used. The Steering Committee approved a flow chart in preliminary form for distribution to all participants.

At a later meeting the same day, the Steering Committee approved the following actions: (1) Ralph Shaw will prepare a draft of a press release with an area map which he will mail to the Steering Committee members; (2) that the Steering Committee should meet at regular periods; (3) the Steering Committee will meet December 4 in the Red Carpet Room at the Denver airport; (4) consultants should not be permitted on the committees or task forces; and (5) the Study Manager is to have working committees and task force chairmen furnish status reports as of December 31 to provide information for the next meeting of the Coordinating Committee.

9. October 15, 1970 -- Coordinating Committee Meeting

The following municipal representatives were recommended for membership on the Coordinating Committee by Alex Radin, General Manager, American Public Power Association, per agreement with Assistant Secretary James R. Smith:

James H. Lundsted	Missouri
Robert O. Marritz	Missouri Basin
Arie M. Verrips	Iowa
Stan Case	Colorado
Homer Engelhorn	South Dakota
Fred D. Diehl	Kansas
Milton Launer	Nebraska
Harold O. Moe	Minnesota

The eight municipal representatives represent over 700 municipal utilities in the study area. Neil Adams, Associated Electric Cooperative, Springfield, Missouri, had also requested membership. It was mentioned that the Cooperative Power Association, Minneapolis, Minnesota, had been inadvertently omitted from the initial invitation to participate and that Minnkota Power Cooperative declined to participate when the study was being organized but it might desire to do so now.

Representatives of the eight municipals and the Associated Electric Cooperative were approved for membership on the Coordinating Committee and representation for Cooperative Power Association and Minnkota Power Cooperative was approved subject to their making application for participation in the study.

The Coordinating Committee also approved the addition of one municipal representative to the Steering Committee. Arie Verrips was selected by the municipals.

Mr. Ralph Shaw reported on the meeting with the energy companies the previous day. Mr. Joe B. Smith, Bureau of Mines, Denver, was then confirmed as a member of the Coal and Byproducts Task Force.

A decision was made by the Steering Committee to use 1970 prices and to provide estimates for 1975, together with the index figures used for escalation.

There will be two study reports: (1) A small but glamorous summary, and (2) a detailed technical supplement.

The location of hydro sites has been restricted to the main stem of the Missouri River and the Rocky Mountain area; the reason being that sites in Minnesota, Wisconsin, and Missouri, for example, would be considered by the local utilities in alternative studies.

A press release will be developed by Ralph Shaw for approval of the Steering Committee for release after the next meeting of the Coordinating Committee in January. In the meantime, each member may report on its own activities in connection with the study but should not report on the whole study.

The municipal group was advised that only staff members of participating utilities could be on the committees but Coordinating Committee members could have their own individual work done by consultants.

A flow chart approved by the Steering Committee was included in a mailing by the Study Manager October 28, 1970.

WORKING COMMITTEE AND TASK FORCE ACTIVITIES

10. Transmission Committee

a. A joint meeting of the Transmission and Load Projection Committees of the North Central Power Study convened in Denver on September 17, 1970.

Mr. Hunkins, Chairman, reported that the years of 1980, 1985, 1990 and 2000 would be used for the study. Base studies would start in 1980 as most companies have power supplies arranged for through 1976-78.

The Load Projection Committee planned to use load projections available from individual companies and project loads beyond those now available. A few large load centers in the study area will be selected for delivery of power. Utilities will be required to come to the load centers for power.

It was stated that computer decks are available for modification for our study. BPA decks will be available for Western loads and USBR-Basin decks will be available for the Eastern area. Load data from the new Federal Power Commission report was handed out and discussed in relation to this study. A transmission map for the Western and Central United States was handed out for discussion of the study area.

Glenn Walkup, Chairman, Technical Studies Task Force, said there will be two separate systems, East and West. A bus list is to be worked up by September 23, 1970. An exploratory study to include between 20 and 200 buses for 1980 period will be run prior to the detailed study. Studies will be run for reliability, conforming essentially with both WSCC and MARCA criteria. It was noted that specific locations for thermal and hydro generation will have to be obtained from the Resources Committee as soon as possible.

b. In a discussion with the Design and Location Task Force it was decided that a ring bus for substation design is to be used for up to six lines with a layout to develop into a breaker and a half scheme for over six lines. Preliminary work to be done by the Design and Location Task Force will include types of compensation, voltage selection, and conductor sizes. Initial cost and design work will start on 765-kv lines. Location of transmission lines was assigned to members on the task force living in the areas. Costs are to be based on the 1970 figures and will be escalated by the Economics Committee. The Task Force will check with the Environmental Committee on types of transmission line construction.

In a telephone call on October 29, 1970, the Chairman advised that no further work will be done until after the November 4 joint meeting with the Resources and Load Projection Committees.

c. On October 13, 1970, the Technical Studies Task Force met. The Chairman of the Resources Committee was asked for information on possible plant locations and they are now awaiting a reply. Indications are that the initial stage of generation for systems to the East may well be in the 3,000-5,000 megawatt range with a smaller amount for the western Rocky Mountain area. Study cases will be set up immediately for exploration of various EHV and UHV systems required for delivery of from 3,000-5,000 megawatts over distances up to about 600 miles. Investigation will be made of various modes of series compensation. Criteria for the load studies were discussed briefly. Comments were made to the effect that phase shift limits over transmission lines of about 30 degrees were typical for existing systems and 22-25 degrees for the initial stage of a new system.

Objectives of this study will be to test various generation transmission plans for steady state and transient stability. The Task Force noted that in at least one recent stability study in the north-central region some turbine generators exhibited a markedly longer swing period than usually observed in stability studies. They thought it may be necessary to simulate regulator and governor action and to look at disturbances over a period of several seconds. Also, some thought needs to be given to load representation to simulate effects of abnormal voltage. (See d. below.) Although no stability runs can be made until load flow bases are ready, this item will be kept on the agenda for meetings in the interim.

Northern States Power Company has provided a descriptive writeup for use of their loss of load computer program. The program provides for numerous options, one of which is use of either seasonal or monthly load and capacity data. The latter required much more data, including unit maintenance information, but is theoretically more precise. The decision whether to use the seasonal or monthly method will be made at a later date. The Task Force plans to use existing data files for this study. They may have to ask for additional data at a later date.

The Task Force felt that an effort should be made to comply with both MARCA and WSCC criteria but there may be stages of transmission system development when full compliance may not be practical.

Assignments were made to Task Force members for checking the base case network and preparation of working diagrams.

Tables of typical transmission line constants for EHV and UHV lines were made available. Constants are not linear functions for long lines of 200 miles or more.

The Task Force plans to complete the following by November 10:

(1) Computation of transmission line constants for typical lines as may be used in the study.

(2) Load flow cases for exploration of elementary transmission schemes.

(3) Checkout of base case network data.

(4) Working diagrams of the base case network.

d. The Study Manager, after reviewing the minutes of the Task Force meeting, called attention in a letter of October 23, 1970, to the possible inference that consideration is being given to doing dynamic stability studies. The Task Force was cautioned that for the first step of the study only classical stability cases are to be run.

Study Manager said that in the event the Transmission Committee believes that dynamic studies are required it should so recommend to the Coordinating Committee. The Coordinating Committee would then discuss the desirability of incorporating these studies in the third step of the program as was discussed in his letter of October 2, 1970.

11. Load Projection Committee

Early action was taken by the Load Projection Committee in a joint meeting with the Transmission Committee to determine precisely what data were required. Following that, on September 28, Virge Dixon, Chairman, Load Projection Committee, wrote and asked the Coordinating Committee members for basic seasonal loads and supply data including generation, purchases, and sales. The seasons for which data were requested are 1980, 1985, 1990, and 2000 (summer of 1980, winter of 1980-81, etc.). Load and supply data forms and a listing of buses were furnished for convenience in reporting. About 70 percent had replied as of November 2.

The committee asked for suggestions or comments on new high-voltage transmission lines beyond additions which were submitted for the MAPP and WSCC studies for 1976.

Another joint meeting of the Transmission Committee with its task forces and the Chairmen of the Resources and Load Projection Committees has been scheduled for November 4 in Denver.

The Load Projection Committee will meet on the following day, November 5, in Denver.

12. Resources Committee

a. On September 23 Chairman of the Resources Committee, Howard Ericksen, advised that:

(1) The Coal and Byproducts Task Force was accumulating inventory and mining cost data and had scheduled a meeting for October 14.

(2) The Hydro-Generation Task Force was proceeding with a survey of potential sites and cost information.

(3) The Thermal Generation Task Force was establishing unit capital and operating costs for thermal units, by sizes, locations and fuels.

(4) The Water Supply Task Force was developing an inventory of water availability and related costs.

The Committee's activities were again discussed with Howard Ericksen, Chairman, on October 30 and he advised as follows:

(1) He will meet with the Transmission Committee and the Load Projection Chairman in Denver on November 4.

(2) The Thermal Generation Task Force had met on October 22 but he had not received a report.

(3) He was aware that the Coal and Byproducts Task Force was working with the Bureau of Mines to get locations of large coal deposits, costs, etc.

(4) He had little information on the Water Supply Task Force. He was advised that the Steering Committee had met with the fuel suppliers on October 14 and that the Bureau had presented cost estimates for the delivery of water at various points. He was also told that the water delivery estimates to all logical points of use had not been completed but would be within the next 3 or 4 months.

(5) He had no recent information on the progress of the Hydro-Generation Task Force. However, this task force is expected to have preliminary data by November 2.

Chairman of the Resources Committee plans to meet as soon as the task forces have sufficient information for such a meeting to be beneficial.

b. The Thermal Generation Task Force is another hard-working group.

Wally Blankmeyer, Chairman, advised that the Task Force is proceeding to develop curves and tables prepared in such a way that all reasonable choices of cooling methods, coal cost ranges, and coal quality ranges are covered without having to wait for specific reporting from any other task force. The Task Force will develop tables and curves on the following items:

(1) Capital costs for generation, cooling methods, etc., except environmental and recreational costs. Capital costs during construction are to be shown annually during the construction period. Interest during construction and property taxes will be supplied by the Economics Committee.

(2) Operation and maintenance expense.

(3) Net heat rates for various unit sizes and load factors.

(a) Fuel consumption in terms of BTU/MW/year with various net heat rates.

(b) Coal requirements in terms of tons/millions of kwh for the various net heat rates and coal BTU content ranges.

(c) Costs for fuel in \$/million kwh for the various BTU consumption rates and fuel cost ranges.

The Thermal Generation Task Force met in Denver on October 22, at which time the above items were reviewed. Details of that meeting were not available at the time this was written.

c. Tom Weaver, Chairman, Hydro-Generation Task Force, on September 21, following a meeting of the Task Force on September 14, asked the members of his Task Force to report on all potential hydro-peaking capability in their area. Since then, on September 30, sites to be considered were restricted to the main stem of the Missouri River and the Rocky Mountain area. All data should be available by November 1.

A meeting has been set tentatively to review the material during the first week in November.

d. The Coal and Byproducts Task Force held its first meeting on September 14.

It was the understanding of the Task Force that the Steering Committee would meet with the fuel suppliers on October 14 in an effort to gather information on coal resources. The Task Force recognized that some committees and task forces needed location of sites for powerplants to continue with their studies. To break this bottleneck, the Task Force planned to make an area map indicating the locations of sizeable coal deposits. The Task Force intended to determine the type and quantity of byproducts likely to be produced by processing plants such as a 100,000-barrel-a-day synthetic gasoline plant. The Task Force was also going to indicate possible sites for thermal plants for use of other committees. It was originally proposed that the site locations would consist of:

3 in North and South Dakota
3 in Colstrip, Montana, area
2 in Gillette, Wyoming, area
1 in Decker, Montana, area
1 in Lake De Smet, Wyoming, area
1 in Hanna, Wyoming, area
1 in Kemmerer, Wyoming, area
1 in Craig, Colorado, area

Subsequent to the meeting on September 14, the Study Manager called the Chairman of the Coal and Byproducts Task Force concerning coal data that is to be prepared by the Bureau of Mines in Denver. The Task Force will meet on October 30 to examine such data as may be available from the Bureau of Mines at that time. Hopefully, it will be possible to determine good plant locations from this data. If so, the cost of water and other services can be determined. Then other committees would have something definite to work with.

e. Phil Q. Gibbs, Chairman, Water Supply Task Force, at a joint meeting of the Steering Committee with the fuel suppliers on October 14, discussed and furnished some cost estimates for delivering water from Boysen and Yellowtail Reservoirs. Additional cost estimates are being worked up and should be available in about 3 months. The Task Force needs to know where thermal powerplants will be located and their water requirements. Water requirements and the location of coal processing plants are also needed.

The Task Force is also studying the feasibility of delivering water from Garrison and Fort Peck Reservoirs. No water can be made available from reservoirs in Region 7 (Denver) but some from Region 4 (Salt Lake) can be used.

13. Economics Committee

The Economics Committee has been hard at work providing figures and methods for use of the working committees and task forces. On October 2, the Chairman of the Economics Committee, Mr. Leon Barrett, furnished escalation figures to all committee chairmen advising that 1975 would be used as a base for the study. However, subsequently the Steering Committee requested that 1970 be used as a base and that this be escalated to 1975 with escalation figures provided. This would enable the utilities to use their own methods and escalation figures to arrive at a base for comparison to suit their individual needs.

The Committee also suggested one consolidated interest rate be used for all thermal generation and transmission facilities. The Committee assumed that all hydro developments would be Federal and that other facilities would be substantially municipal, cooperative, and investor-owned utilities. Basis for this was that no single group would be in a position to finance the entire project.

The Committee met on October 5 in Minneapolis. It assumed that generation capacity in the Montana-Wyoming area would initially amount to over 3,000 megawatts with EHV transmission (500-kv or 765-kv) to Minnesota, Iowa, and Missouri to the East and possibly Oregon and California to the West. Actually, there was doubt that there will be any transmission that far West.

The Committee proposed first that the analysis must show whether or not the overall project is economically sound. Second, sufficient information must be provided so that the individual utility (municipal, cooperative, or investor-owned) can determine whether its proposed share in the overall project is economically competitive with other alternatives. It has described the various alternatives the Committee considered in its deliberations.

The method of evaluating total revenue requirement that the Committee considers best assumes the principle of the establishment of a separate organization. It was pointed out that such an organization was not envisioned but the principle was used for convenience of calculations. The Committee envisions a high debt corporation with the participants owning the equity. It also assumed that the bonds would be taxable. This method allows the use of a single value for the revenue requirements and eliminates the need to predetermine individual ownership, since the revenue requirements of the participants will not significantly affect the revenue requirements of the composite organization. Because of these advantages the Committee recommended this method for determining overall annual revenue requirements for the proposed project. The Committee assumed the overall financing would be approximately 90 percent bond at 8 percent interest (taxable type) and 10 percent equity with the required return of about 10 percent. Since the project involves a considerable number of states, the Committee plans on using an average composite Federal and State income tax of 50 percent. Property taxes would be developed for each state with which the project is involved based on an average state-wide percentage. An overall life of 40 years is assumed based on the available water rights. Insurance is assumed to be approximately .1 percent.

Hydro-peaking capacity was assumed to be of two types: Additions to the Missouri River existing damsites or entirely new developments. Additions to the existing hydroplants would be Federally owned and, therefore, the annual revenue requirements associated with a Federal development would be used. The new sites could either be Federally owned or developed by this composite organization proposed. This would probably require an analysis of the individual site to determine anticipated ownership.

The above method will provide sufficient information to determine the economic feasibility of the overall project. However, it does not allow an individual utility to determine the relative merits of a share in this project versus other available alternatives. To achieve this requirement the Committee proposed to include in the report both the capital expenditures and the annual operating cost in sufficient detail so that an individual utility could apply its own revenue requirements and evaluate a share in the overall project.

14. Environmental Committee

There has been no formal progress report from the Environmental Committee. However, in response to a telephone call the Chairman, George Paraskeva, advised that the task forces had been accumulating information and data for use with their report. The chairman of the Land Reclamation Task Force has discussed the problem with a Task Force member located in Salt Lake City--specifically about possibilities of developments in Idaho and Utah. It is doubtful that there will be anything in that area requiring attention of the Environmental Committee. The Land Reclamation Task Force will furnish its recommendations and cost figures as soon as it is advised of thermal powerplant locations. This committee on Land Reclamation is in an apparently good position from an experience point of view as both Basin Electric and MDU have been working with this problem in connection with their own operations.

The Chairman of the Environmental Committee advises that he will furnish his report on what the Committee plans to do within the next few days.

15. Legal Committee

Richard D. Wilson, Chairman, Legal Committee, advised on September 29 that the Committee planned to meet the first week in November. However, in a telephone conversation with him on October 30, he advised that some other matters had come up that would delay the meeting until perhaps the third week.

16. Report Committee

The Report Committee has had two meetings. The first was held September 14 to formulate questions, to define the Committee's function, and to establish a plan of action.

The Committee met again on September 30. The members developed explanations of procedures and responsibilities for preparation of the NCPS report.

There will be two separate volumes to provide complete coverage of the study activity. Volume I will be a polished report covering the most significant results of the NCPS activity. Volume II will be a collection of technical appendices supplied by each of the six reporting committees.

Volume I will have two sections. The first section will be prepared by the Report Committee and will highlight the study and the results for the best system plans. The second part of Volume I will consist of finished summary reports of each committee which will support the best system plans. The Report Committee will further define the contents of the parts for the benefit of the reporting committees.

All committees will be instructed to supply a glossary of terms and perhaps some other material for purposes of clarification.

Volume II of the report will consist of in-depth technical backup material from each committee. Except for introductory material which will be prepared by the Report Committee, no attempt will be made to provide text to tie the appendices together.

Detailed explanations and procedures for preparation of the report will be transmitted to the committee chairman in a few weeks. The Report Committee plans to meet again in 1970 for such further clarification of instructions as may be necessary and to discuss detailed plans for the physical features of the report.

AQUEDUCT - YELLOWSTONE RIVER TO COLSTRIP
COST OF WATER DELIVERIES

Destination	Colstrip Area
Aqueduct size	66 inch
Aqueduct capacity	130 c.f.s.
Annual water delivery	90,000 acre-feet

Costs	($1,000)
Intake channel	300
Chlorination station	140
Pumping plants	6,030
Aqueducts	16,340
Rights-of-way and access roads	80
Surge tanks, forebay tanks, & pipestands	2,230
Water level control well	10
Terminal storage	2,570
Telemetering control	850
Field costs	28,550
Engineering and administration (25%)	7,140
Escalation factor to 1977 (18.3%)	6,530
Interest during construction (3-year period @ 3.463%)	2,190
Total Project Investment	44,410
Annual Costs	
Amortization of investment (50 years @ 3.463%)	1,881
Operation, maintenance, and replacements	167
Pumping power (4 mills/kwh)	512
Basic water charge ($9/A.F.)	810
Total Annual Costs	3,370
Total Annual Costs Per Acre-Foot	(37.40)

Offstream Reservoir (To firm up yield of about 450,000 A.F.)

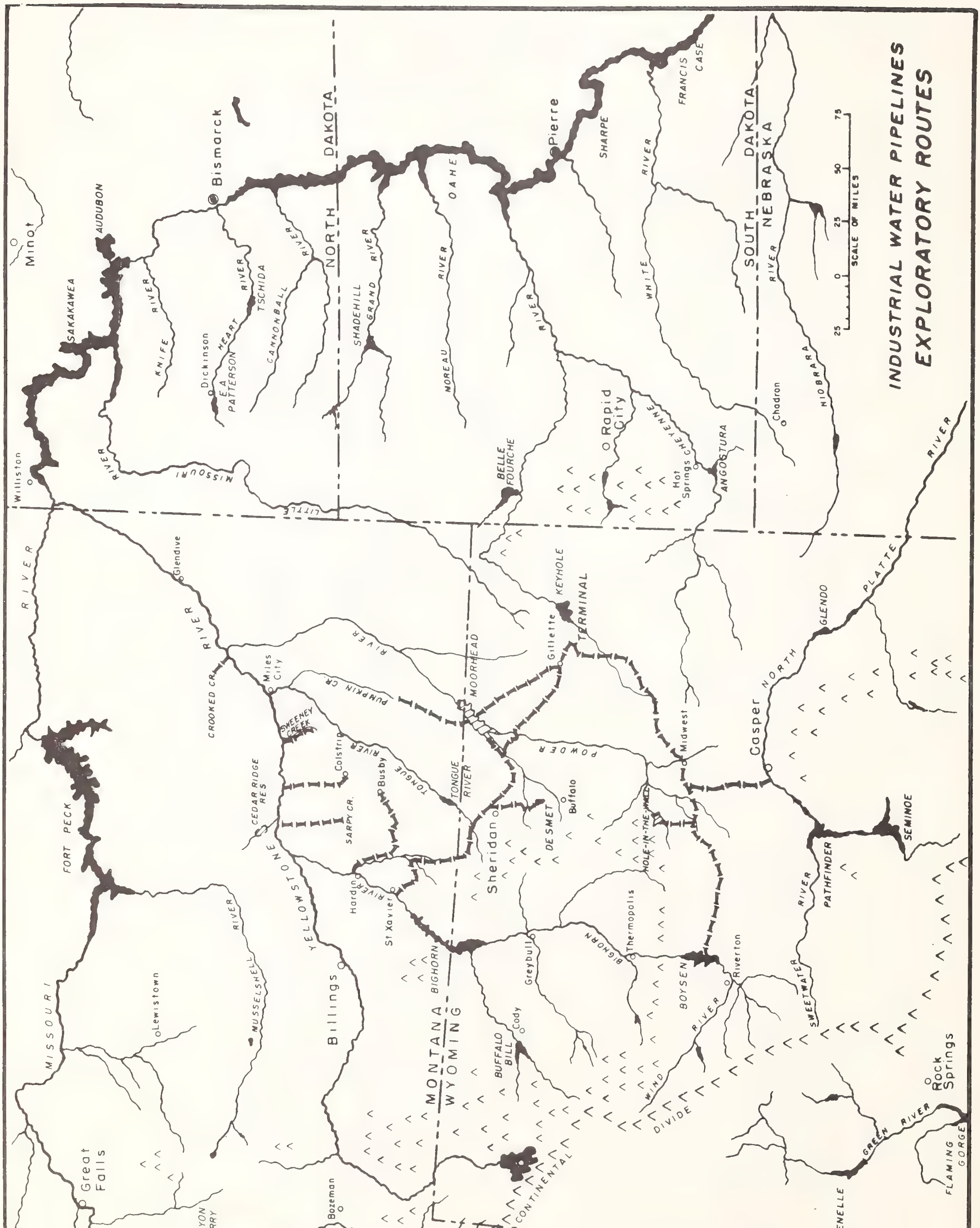
Offstream storage would be required to firm up an occasional dry month of Yellowstone River flow. Storage at the Cedar Ridge site would firm up a yield about 5 times that required for the Yellowstone to Colstrip Aqueduct. Therefore, costs allocated to the Yellowstone to Colstrip Aqueduct for the purpose of this preliminary analysis would be as follows:

Cost of offstream storage	($1,000)
Field cost	14,000
Engineering and administration	3,700
Escalation factor to 1977	3,240
Interest during construction	1,090
Total Project Investment	22,030
Annual Cost	
Amortization of investment	933
Operation, maintenance, replacements, and pumping power (average annual)	7
Total Annual Cost	940
Total Annual Cost Per Acre-Foot	(2.10)

AQUEDUCTS - ST. XAVIER TO GILLETTE
COST OF WATER DELIVERIES

REACH I	St. Xavier to Parkman Divide Area		
Aqueduct size	72 inch	108 inch	144 inch
Aqueduct capacity	200 cfs	500 cfs	1,000 cfs
Annual water delivery	139,000 A.F.	347,000 A.F.	694,000 A.F.
Costs	($1,000)	($1,000)	($1,000)
Field costs (July 1970 Prices)	78,450	130,580	202,000
Engineering and administration (20%)	15,690	26,120	40,400
Escalation factor to 1977 (18.3%) 1/	17,230	28,680	44,360
Interest during construction (3-year period @ 3.463%) 2/	5,790	9,630	14,900
Total project investment	117,160	195,010	301,660
Annual costs			
Amortization of investment (50 years @ 3.463%) 2/	4,962	8,259	12,775
Operation, maintenance, and replacements	195	260	380
Pumping power (4 mills/kwh)	1,060	2,504	5,048
Total annual costs	6,217	11,023	18,203
Total annual costs per acre-foot	(44.70)	(31.80)	(26.20)
REACH II	Parkman Divide to Tongue River (Acme)		
Aqueduct size	60 inch	90 inch	120 inch
Aqueduct capacity	125 cfs	400 cfs	900 cfs
Annual water delivery	87,000 A.F.	278,000 A.F.	625,000 A.F.
Costs	($1,000)	($1,000)	($1,000)
Field costs	7,700	17,060	32,960
Engineering and administration	1,540	3,410	6,590
Escalation factor to 1977	1,690	3,750	7,240
Interest during construction	570	1,260	2,430
Total project investment	11,500	25,480	49,220
Annual costs			
Amortization of investment	487	1,079	2,084
Operation, maintenance, and replacements	36	49	73
Pumping power (Reach II gravity flow)	0	0	0
Total annual costs	523	1,128	2,157
Total annual costs per acre-foot	(6.00)	(4.10)	(3.50)
REACH III	Tongue River (Acme) to Clear Creek Divide (Ulm)		
Aqueduct size	48 inch	90 inch	120 inch
Aqueduct capacity	70 cfs	300 cfs	600 cfs
Annual water delivery	49,000 A.F.	208,000 A.F.	416,000 A.F.
Costs	($1,000)	($1,000)	($1,000)
Field costs	29,380	54,000	87,300
Engineering and administration	5,880	10,800	17,460
Escalation factor to 1977	6,450	11,860	19,170
Interest during construction	2,170	3,980	6,440
Total project investment	43,880	80,640	130,370
Annual costs			
Amortization of investment	1,858	3,415	5,521
Operation, maintenance, and replacements	114	149	216
Pumping power	392	911	1,790
Total annual costs	2,364	4,475	7,527
Total annual costs per acre-foot	(48.20)	(21.50)	(18.10)
REACH IV	Clear Creek Divide (Ulm) to Gillette		
Aqueduct size	48 inch	78 inch	108 inch
Aqueduct capacity	70 cfs	200 cfs	450 cfs
Annual water delivery	49,000 A.F.	139,000 A.F.	312,000 A.F.
Costs	($1,000)	($1,000)	($1,000)
Field costs	46,220	88,400	159,410
Engineering and administration	9,240	17,680	31,880
Escalation factor to 1977	10,150	19,410	35,010
Interest during construction	3,410	6,520	11,760
Total project investment	69,020	132,010	238,060
Annual costs			
Amortization of investment	2,923	5,591	10,082
Operation, maintenance, and replacements	283	358	518
Pumping power	247	664	1,484
Total annual costs	3,453	6,613	12,084
Total annual costs per acre-foot	(70.50)	(47.60)	(38.70)
BRANCH LINE	Clear Creek Divide (Ulm) to Lake DeSmet		
Aqueduct size		60 inch	
Aqueduct capacity		75 cfs	
Annual water delivery		52,000 A.F.	
Costs		($1,000)	
Field costs		11,420	
Engineering and administration (25%)		2,860	
Escalation factor to 1977		2,610	
Interest during construction		880	
Total project investment		17,770	
Annual costs			
Amortization of investment costs		753	
Operation, maintenance, and replacements		56	
Pumping power		6	
Total annual costs		815	
Total annual costs per acre-foot		(15.70)	

1/ Escalation factor: 1970 to 71 (4%), 1971 to 72 (3%), 1972 to 77 (2% per year).
2/ Water Supply Act of 1958 repayment rate in effect for FY 1971; future rates unknown at this time.
Note: Annual costs do not include the basic water charge of $9 per acre-foot.


INDUSTRIAL WATER PIPELINES
EXPLORATORY ROUTES
SCALE OF MILES
25 0 25 50 75
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
MONTANA
WYOMING
IDAHO
UTAH
Minot
Bismarck
Williston
Dickinson
Pierre
Rapid City
Hot Springs
Chadron
Glendive
Miles City
Gillette
Moorhead
Colstrip
Busby
Sheridan
Buffalo
Midwest
Casper
Hardin
St Xavier
Billings
Greybull
Thermopolis
Riverton
Cody
Lewistown
Great Falls
Helena
Bozeman
Rock Springs
SAKAKAWEA
AUDUBON
E.A. PATTERSON
SHADEHILL
OAHE
SHARPE
FRANCIS CASE
BELLE FOURCHE
ANGOSTURA
KEYHOLE
TERMINAL
FORT PECK
SWEENEY CREEK
CEDAR RIDGE RES
DE SMET
HOLE-IN-THE-WALL
BOYSEN
BIGHORN
BUFFALO BILL
CANYON FERRY
PATHFINDER
SEMINOE
GLENDO
FONTENELLE
FLAMING GORGE
CONTINENTAL DIVIDE
MISSOURI RIVER
LITTLE MISSOURI RIVER
KNIFE RIVER
HEART RIVER
TSCHIDA
CANNONBALL RIVER
GRAND RIVER
MOREAU RIVER
CHEYENNE RIVER
WHITE RIVER
NIOBRARA RIVER
NORTH PLATTE RIVER
POWDER RIVER
PUMPKIN CR.
CROOKED CR.
TONGUE RIVER
SARPY CR.
YELLOWSTONE RIVER
BIGHORN RIVER
MUSSELSHELL RIVER
WIND RIVER
SWEETWATER RIVER
GREEN RIVER

December 31, 1970

Synopsis
Progress Report No. 3
North Central Power Study

17. The Study Manager in his November 13, 1970, letter to the Coordinating Committee and Participants explained "phases and steps."

Phase I, step 1--Determine generation costs for various sizes from 5,000 mw upward; step 2--determine costs for reliable transmission for various amounts of generation; and step 3--determine the cost of delivered power. Then publish the NCPS report.

Phase II, step 1--Participants are to advise how much power they want and the location; step 2--redo transmission studies based on step 1 requirements and determine cost East and cost West.

Phase III--Implement construction.

18. The Study Manager's letter of November 19 advised that it was intended that MARCA and WSCC reliability standards be met at all times. However, during early stages of construction he commented that it might be desirable to use generation reserves at load centers.

19. a. Transmission Committee--Broad-base reconnaissance-type studies are underway to explore technical feasibility of multiple lines. EHV power system and unit costs are being determined. Efforts thus far are to the East. Work toward the West will be initiated on receipt of data.

Power deliveries will be made at a few large capacity 230-, 345-, 500-, or 765-kv buses in the load area. Subtransmission systems will not be developed.

b. Technical Studies Task Force--A detailed base case is being assembled for 1980 to study the initial stage of generation and transmission development. If possible, a detailed study will be made of 1985 conditions.

Elementary studies are now being run for various configurations of EHV and UHV transmission for different levels of generation. Several cases have been run at 3,000-20,000 mw to evaluate effects of different modes of series compensation and to determine approximate circuit capabilities.

Data are being checked and diagrams prepared for the Rocky Mountain area (Western System). BPA has offered to furnish data decks for the PNW.

It is intended that classical study techniques be used for stability studies. Stability runs cannot be made until the load flow study has progressed further.

A program for use in determination of risk levels of loss of generating capacity has been made available by Northern States Power. Preliminary cases will be run as soon as time permits. It is now envisioned that this study will include all existing generation (to 1980) in the study area and will focus on annual peakload conditions.

c. Design and Location Task Force--The Task Force wants 800 kv as maximum voltage on the 765-kv system. They will concentrate on 500- and 765-kv a.c. systems for unit costs.

20. Load Projection Committee--Basic load has been received except for UP&L which is expected soon. East system data should be ready for the computer by January 1. The first case studied will be for the East system for summer of 1980 and winter of 1980-81. West system data will be prepared as soon as balance of information is furnished.

Municipal load data have been furnished in summary form by states. First case studies will include those covered by Coordinating Committee member reports.

21. Resources Committee

a. Coal and Byproducts Task Force--It has furnished a draft of a report to members of the Task Force for review and comments.

The general location of the coalfields and the major railroads, rivers and cities is provided. The location and generation support capability of the coal sites are given. A tabulation by states with maps shows the locations having sufficent strippable coal reserves to serve 42 plants of 1,000 mw to 10,000 mw. Additional data will be used to modify or extend the tabulation. The Task Force feels that it will not change substantially and that the data now provided may be used by the various committees.

The Task Force is unable to predict when or where synthetic fuel plants will be erected. However, the following general statements can be made:

1. Synthetic fuel plants will be in direct competition with powerplants for the large (3000-mw or larger capability) reserves of strippable coal.

2. The first application will probably be for the production of synthetic pipeline gas. Any such plants will probably not produce sufficient byproduct fuel, such as char, to carry a 1000-mw generating plant.

3. Synthetic liquid fuel plants of the minimum size of 100,000 barrels per day could each supply char adequate for a 1,500-mw base load powerplant.

b. Hydro-Generation Task Force--It has data on 28 potential sites in the Rocky Mountain area. Due to the high estimated capital costs only about 17 of the sites should be considered by the Transmission Committee.

A list of the potential hydro sites with estimated capital costs has been furnished and will be given to the Transmission Committee for consideration in their transmission plans.

c. Thermal Generation Task Force--See the Second Progress Report dated November 4, 1970. No additional information is available.

d. Water Supply Task Force--An estimate of water supplies which could be developed and utilized for the NCPS appears to be limited to 1,700,000 a.f. Quantities and locations have been tabulated. Water requirements have been computed for various size developments for wet tower, cooling pond, and flow-through type of cooling.

22. Legal Committee--It has submitted an interim report on December 7 advising that before it can proceed it needs answers to a number of questions depending on the output of other committees. The Committee reported that it knows of no overriding legal obstacles to any proposed development which it may finally be asked to consider. The Committee stands ready to assist any other committee or task force with any specific legal questions that they may have.

23. Economic Report--See the Second Progress Report dated November 4, 1970. No additional information is available.

24. Report Committee--A proposed plan has been submitted for review by the Study Manager. Intention is to transmit the plan to the committees for further comments subject to the foregoing review.

Unit costs and time requirement for typing, art work, drafting, printing, and binding are being gathered. The Committee hopes to obtain rough drafts of charts, graphs, and other nontext material in advance of the June-July deadline.

25. Environmental Committee--Study outlines of the Land Reclamation and Pollution Control Task Forces have been prepared and submitted.

26. Steering Committee meeting December 18, 1970. The following subjects were discussed as noted:

a. A publicity release draft is in the process of review for possible release at the Coordinating Committee meeting on January 19.

b. It was concluded that most realistic legal work could not start until Phase II was underway.

c. Load data on the West system indicates it may be inadequate to justify a reliable transmission system without adding a dummy load for the Pacific Northwest. The Study Manager was instructed to eliminate PNW loads from the study.

d. Exception was taken of reporting the cost/kwh. Preference was to show investment costs only. This item was left unresolved and the Coordinating Committee will be asked to rule on it.

e. The proposal that some hydro peaking power be traded for energy to firm some peaking power retained by the Bureau was discussed at some length. Question was raised as to how much was involved and how would it be marketed. The Study Manager was asked to explain hydro-thermal integration and the Government's interest.

f. Question was raised about the validity of the postage stamp rate. The Committee suggested that the cost of power delivered in Wyoming, for instance, should be lower than in Minnesota. The Study Manager was asked to devise a formula for different rates at different delivery points.

g. Question was raised on available water for thermal plants. The Study Manager indicated that water was limited and that dry cooling may be required later. Opinion was that dry cooling would be expensive and technology had not advanced sufficiently for adaption with the unit sizes that should be considered. The Study Manager agreed to advise on the available water supply.

h. The outline and method of writing the final report received general approval.

i. All but six of the participants have made advanced deposits of $1,500. Instructions were given to the Study Manager to call those participants who have not done so.

Synopsis
Progress Report No. 4
North Central Power Study

27. Steering Committee Meeting, January 12, 1971. The following subjects were discussed:

a. Harold Aldrich, Regional Director, Bureau of Reclamation, discussed the Government's role in the NCPS as far as power requirements are concerned. Without the Missouri River additional peaking capacity, the Government would expect to obtain the following power from the NCPS development: (1) Capacity and energy for pumping water for delivery to coal sites; (2) capacity and energy to maintain the Bureau's existing marketing level (1977); and (3) surplus energy during low water years to maintain the Bureau's firm power commitments.

b. It was agreed the study would be run with thermal power only and also with thermal power in some combination of hydro-peaking capacity.

c. Transmission costs will be allocated to participants according to three methods: (1) An average rate, (2) kilowatt-mile rate, and (3) kilowatt-zone rate.

d. There are some 1,700,000 acre-feet of water available for cooling of thermal generation plants which appears to be adequate for the purposes of the study.

28. Steering Committee Meeting, January 18, 1971.

a. The role of the Legal Committee in Phase I of the NCPS was discussed. It was agreed the committee's work would be quite limited.

b. It was agreed that generation and transmission reserves would be carried at load centers rather than be at the coalfields or built into the transmission system.

c. The role of the East-West ties and Pacific Northwest loads were reviewed.

29. Steering Committee and Chairmen, Committees and Task Forces, Meeting on January 18, 1971. Discussions of individual working groups are summarized below.

a. Legal Committee. This Committee requires detailed information before it can do constructive work and except for answering specific questions, this Committee expects to do little work for Phase I of the study.

b. Load Projection Committee. Most of the load data are available and the remainder will soon be supplied. The Committee is cross-checking to avoid duplication and to eliminate errors.

c. Transmission Committee. The Steering Committee approved elimination of computer stability studies for Phase I unless requested at a later date. It was decided that the Transmission Committee would be responsible for transmission environmental consideration.

d. Resources Committee. All work by this Committee and its Task Forces is progressing satisfactorily. Water supply costs as well as coalfield supply and costs have been developed. The thermal generation as well as the hydro generation data have been developed. All four Task Forces are starting to draft reports.

e. Environmental Committee. The first draft on land reclamation has been completed and work is progressing on the pollution considerations.

f. Economics Committee. Basic costs have been developed and supplied to other committees; however, these costs will be reviewed and revised values will be supplied if necessary.

g. Report Committee. An approved format for the two reports has been supplied to all committees.

30. Coordinating Committee Meeting, January 19, 1971.

a. The Coordinating Committee was brought up to date on the work progress as well as on problem areas and how they were resolved.

b. The Coordinating Committee requested that the Corps of Engineers be contacted to insure the method for costing peaking additions on the main stem and pumped storage was on the same basis.

c. The Committee agreed that the role of the East-West ties and the Pacific Northwest load should be unchanged.

d. A publicity release was approved for use whenever needed.

e. The Committee approved the theory of restricting the study work to only considering existing technology. During later phases of the study such items as MHD generation and Direct Current breakers would be considered if technologic break-throughs were made by that time.

31. Steering Committee Meeting, February 26, 1971.

a. A detailed discussion of the transmission studies resulted in approval of a study outline which among other things approved:

(1) Elimination of computer transmission studies on the Western system.

(2) As high as 40,000 megawatt development for Eastern loads and 10,000 megawatts for Western loads.

b. The Committee concluded the Corps of Engineers should not be recommended for membership on the Coordinating Committee.

c. The Committee authorized the Study Manager to be interviewed and furnish information for magazine articles.

d. Seven new working committee and task force members were approved.

e. Study Manager reported all 36 Coordinating Committee members had paid the required $1500.

32. A January 28, 1971, newspaper article on the NCPS is attached for your information. The article is fairly accurate.

33. A February 2, 1971, letter from the Study Manager to working groups advising them of latest instructions is attached for your information.

34. A March 12, 1971, letter from the Study Manager to working groups giving costing instructions is on page II-33.

State Coal and Water Pack Power

By DAVE EARLEY
Gazette Staff Writer

Regional coal and water resources, mostly in Montana, are suspected to hold a potential 240,000 megawatts of electrical energy.

That's enough to light up 2.4 billion 100-watt light bulbs.

It's also enough to light up some 778 power distributors in a 13-state area who are engrossed in deciding what to do with all this potential electricity.

A research task force for the North Central Power Study began work in September to assess possibilities in the coal-and-water-rich Montana area.

After this, the consortium of public and private power companies will plan for large scale production. The three-phase study, they feel, could result in electrical wealth throughout the area bounded by Idaho, Utah, Missouri and Wisconsin, beginning in 1978.

PHASE I is expected to be complete late this year with a forecast of the cost of electrical energy in Iowa, for instance, if it were produced in a giant thermal generating unit atop a Montana coalfield, and transported via an equally giant transmission line with a capacity of, say, 500,000 volts.

Or, maybe, 750,000 volts.

Phases II and III will include commitment by various power distributors to buy energy, and construction of the generating plants and transmission lines.

It is a large-scale program intended to take advantage, as Bill Graham puts it, of the "economies of size."

"To give you an idea of the magnitude, says Graham, regional power supervisor for the federal Bureau of Reclamation and study manager for NCPS, "between 1978 and the year 2000, energy output from these resources could range up to 100,000 megawatts at a time.

"FOR COMPARISON, consider that the largest generating unit in Montana now is at Yellowtail Dam, with a capacity of 250 megawatts."

The state's largest transmission line, he adds, has a capacity of 230,000 volts.

Graham is the only federal representative on the 36-member NCPS coordinating committee.

Other members include representatives of 19 investor-owned power companies (including Montana Power and Montana-Dakota Utilities), 6 co-ops (including Basin Electric), and 2 public power districts. There are also eight members representing 750 municipal power systems.

Electrical energy can be produced by either hydro-or thermal—generating units, says Graham. To date, the task force has tentatively considered about 20 sites with a hydro-generating potential of, perhaps, 40,000 megawatts.

Hydro-generation includes the "pump storage" technique, says Graham. Water from a reservoir is used to operate the turbines during the day, and then pumped back over the dam at night to be re-cycled the next day. Energy from pumping operation would come from thermal-generating units which can't be efficiently shut down during low-demand nighttime hours.

But the really big potential, Graham points out, is in the estimated 300 billion tons of recoverable coal in the area, much of it in Montana.

COAL WOULD be used in "mine mouth" thermal-generating plants. The coal is burned to make steam to operate turbines. Afterwards the water is cooled and, as much as possible, re-cycled.

Forty-two potential thermal-generating sites have been located so far: 21 in Montana, 15 in Wyoming, 4 in North Dakota, and 1 each in South Dakota and Colorado.

These sites are estimated to have a potential for 200,000 megawatts of electrical energy.

To avail itself of the "economies of size," the group has not considered any energy source with a potential of less than 1,000 megawatts. (Again, Graham reminds, Yellowtail's capacity is 250 megawatts.)

Moreover, the site's capacity must be sustainable for 35 years. And only coal which can be obtained by strip mining is considered.

The 240,000 megawatts potential would not be produced all at once, of course, or at the same time. If all goes well, 1,000-megawatt unit might be constructed first, another a few years alter, and so on.

"We might cover half the sites by 2000."

Graham refuses to estimate the cost of such thermal plants, although he points out that a 400 megawatt unit planned by one cooperative will probably cost about $60 million.

Cost, including plant and transmission lines, will be about 30 per cent higher for environmental protection, Graham estimates. Montana's environmental standards will catch up to those of other states, he belives,

"And, we'll build to meet them."

"The thermal plant would produce no more smoke than if it were to be built in downtown Chicago." Transmission lines would go around mountains rather than over them, and so on.

Heat Pollution?

"OUR WATER would be too precious to waste it heating Montana's streams." Water must be purified to be used in the stream trubines, he points out. Some might be lost by evaporation in a cooling tower — but no more than absolutely necessary, he says, and that won't affect streams.

Advantage to surrounding power users, says Graham, is that freight charges for shipment of bulky coal to local generating plants are eliminated.

The coal has to be mined either way, he explains. But the mined-cost of coal used in Montana might range between 9 to 18 cents per million BTU (British Thermal Units — a heat measurement). He estimates the cost at between 35 to 50 cents per million BTU in the midwestern states, now, although use of "unit trains" for transport in some cases may cut this coal cost to 25 to 30 cents per million BTU.

Each member of the consortium has donated $1,500 toward computer costs, to find out the economic facts.

How does it look so far?

"I personally — and this is strictly my personal opinion — feel sure that with low cost fuel and bulk transmission lines we can beat anybody's cost.

"But then," Graham grins, "if I were always right we wouldn't need computers."

<u>36. Steering Committee and Chairmen, Committees and Task Forces Meeting, March 29. Following are the high points of the meeting:</u>

a. The Land Reclamation appendix report was submitted. Cost of grading and reseeding was reported as not significant.

b. Electrostatic precipitation will be required and provision will be included for an "adder" to cover the possible installation of scrubbers for sulphur removal.

c. Thermal generating plants will be located in the Colstrip-Gillette area.

d. The original escalation factors were questioned as being too low. It was concluded that 5 percent compounded annually would be more realistic.

e. Overburden thickness is to be included in the Coal and Byproducts Task Force report.

f. The delivered cost of water to selected generation areas without participation by the energy companies will be computed.

g. The Economics Committee has prepared proposed interest and property tax rates for use in developing total investments. Composite interest rates during construction have been developed.

h. Percent of total load for each category of customers - municipals, investor-owned, cooperatives, etc. - is to be furnished the Economics Committee.

i. Transmission lines for study purposes will originate in the Gillette area. From 12 to 16 UHV lines will be required for the East system with series compensation up to 80 percent. It was suggested that 65 percent should be the maximum but is to be investigated. (80 percent has since been agreed to on the basis of information furnished by the Task Force.) Environmental factors are being considered by the Design and Location Task Force.

j. In addition to the appendix report each Task Force and Committee is to furnish a brief summary report. (Detail instructions have since been issued.)

k. Reports are to be furnished to each member of the Steering Committee, the Chairmen of the Economics and Reports Committees, the Study Manager, and Committee Chairman if a Task Force report.

37. Steering Committee Meeting, March 29, 1971.

a. The Transmission Committee will compare costs of a 3,000-mw development on the Knife River near Beulah, North Dakota, with a similar installation in the Gillette, Wyoming, area. Results will be considered at the next Steering Committee meeting on May 7.

b. The validity of the composite revenue rate figure was questioned. The Economics Committee was asked to investigate the possibility of using curves for various categories from which kwh costs could be read.

c. The Steering Committee agreed to submit a recommendation to the Coordinating Committee to clarify the position of the NCPS regarding closure of the East-West ties.

d. The Study Manager expressed the hope that the study would not fall behind schedule as a result of changes requested by the Steering Committee.

38. Coordinating Committee Meeting, March 30, 1971.

a. Individual committee and task force work progress was reported.

b. All load data have been submitted to the Transmission Committee.

c. The Thermal Generation Task Force was asked to summarize the total costs of generation.

d. The cost of water with and without energy company participation will be investigated.

e. The total of 3000 mw of hydropeaking capacity is being studied for the East system.

f. Coal costs range from 11¢ to 20¢ per million BTU's. Overburden data will be in the report.

g. A 3000-mw development in North Dakota will be compared to a similar development at Gillette, Wyoming, by the Transmission Committee using 500-kv facilities.

h. Series compensation of 80 percent is being considered for the East system. The Committee will investigate to see whether it should be limited to 65 percent.

i. Lattice-type towers will be used for 80 percent of line length and dressed-up lattice-type for the remaining 20 percent.

j. The following are recent modifications to the study:

(1) There will be no West system transmission computer study.

(2) Investigation of a 3000-mw development in North Dakota.

(3) Area for development has been designated the Colstrip-Gillette area. The Gillette area will be the origin of transmission lines.

(4) Water costs with and without energy company participation will be investigated.

(5) Six municipal representatives have been added to task forces and committees.

(6) The Study Manager's costing instructions are being revised.

(7) Summary reports by task forces are now required in addition to appendix reports.

(8) The Economics Committee was asked to investigate the possible application of graphs from which each customer category could get kwh costs.

(9) The NCPS position regarding the East-West ties was clarified. For study procedure they will remain open.

(10) The first draft of the NCPS should be ready for the Coordinating Committee near the end of August.

40. Steering Committee and Chairmen, Committees and Task Forces Meeting - May 7, 1971.

a. Beulah vs. Gillette 3,000 mw development. Conclusion was that the Gillette area study would be included in the report. The lignite resources of North Dakota would be alternate source for interested participants in later phases of the study.

b. The Economics Committee Chairman presented typical curves that could be used to obtain m/kwh for any participant for each level of development and also by various distance methods.

c. Series compensation up to 80 percent will be used for long transmission lines. The Transmission Committee is slightly behind schedule.

d. The Water Supply Task Force expects to complete its appendix report draft by May 28.

e. West System Delivery Point - Medicine Bow, Wyoming. Arie Verrips, municipal representative, asked that further consideration be given to alternatives to the Medicine Bow delivery point. After full consideration of several alternatives the consensus of the Steering Committee was to proceed with only the Medicine Bow and generation bus bar delivery points.

f. Transmission Utilization. Using 500 mw and 1,000 mw generating units, maintenance outages, and reserves, the transmission utilization will vary between 92½ percent to 97½ percent. The Study Manager indicated and the Steering Committee approved that anything above 90 percent would be satisfactory.

g. Coal and Byproducts Task Force. Overburden data is needed yet.

h. Thermal Generation Task Force. The task force will not have cost figures for SO_2 air pollution. The report is being prepared without these figures but with a notation that the cost for these facilities must be added to the cost of generation.

i. Hydro Generation Task Force. The appendix report draft has been completed and is being distributed.

41. Steering Committee Meeting with Committee and Task Force Chairmen - June 23, 1971, Sheraton Inn, Denver, Colorado.

The Chairman opened the meeting stating that from the many report drafts received it appeared that work was progressing in good order. He then asked for corrections or comments on the fifth progress report and received none.

The Steering Committee approved the following changes in personnel assignments:

1. Glenn Walkup replaces Harvey Hunkins as Chairman of the Transmission Committee. Mr. Hunkins is being transferred to the Bureau's Washington, D.C., office.

2. Clark Rose replaces Mr. Walkup as Chairman of the Technical Studies Task Force.

3. Robert Hayes replaces Jerry Cookson on the Hydro-Generation Task Force since Jerry retired on May 31, 1971.

The Steering Committee discussed the Study Manager's May 17, 1971, letter concerning the Gillette-Colstrip vs. Beulah generation comparison. A slight modification was made and the approved paragraph is attached for information.

The Study Manager cautioned the chairmen to be sure that all members of their groups are aware of the committee or task force work so a united effort rather than an individual effort can be obtained.

Reports of the individual working groups were discussed as follows:

A. Load Projection Committee. Draft of summary report submitted May 19. Expect draft of appendix report next week.

B. Transmission Committee. Draft of summary report expected next week. There will not be an appendix report since basic data will be in the two task force reports.

C. Technical Studies Task Force. Expect to have first drafts of both reports for submittal next week.

D. Design and Location Task Force. A draft of a summary report was distributed at the meeting. A draft of the appendix report is expected in two weeks.

E. <u>Resources Committee</u>. Will not have reports.

F. <u>Hydro-Generation Task Force</u>. The draft of the appendix report was submitted May 1971 and the summary draft is expected next week.

G. <u>Thermal Generation Task Force</u>. Appendix report draft submitted June 1971 and summary draft in two weeks.

H. <u>Coal and Coal Byproducts Task Force</u>. Summary draft was submitted January 1971 and appendix draft expected in two weeks.

I. <u>Water Supply Task Force</u>. Summary draft submitted June 1971 and appendix draft submitted May 1971.

J. <u>Environmental Committee</u>. Will not have reports.

K. <u>Land Reclamation Task Force</u>. Appendix report submitted March 1971; summary report expected in one week.

L. <u>Pollution Control Task Force</u>. Both reports are expected next week.

M. <u>Economics Committee</u>. Just starting its work. (Later target date for both reports given as July 8.)

N. <u>Legal Committee</u>. Both reports submitted May 1971.

O. <u>Report Committee</u>. Expect to have report draft by August 1.

The Study Manager stated that outside the work of the Economics Committee and the costing of the western transmission system, all the detail data work was completed so only the reporting remained. It appears that the study can still meet our original schedule.

The Study Manager distributed comments on the individual report drafts that had been previously submitted. Other comments were made at the meeting and are highlighted below:

A. The cost of water at the North Dakota sites was questioned as well as the cost of generation. This was resolved when the study criteria was explained and also the new paragraphs in the Thermal Generation Task Force report draft.

B. A question was raised as to why there was a 500-kv tap at Fort Thompson when the load flow was only 90 mw. It was explained that due to the length of line a sectionalizing station was required anyway.

C. Concerning the hydro report, it was explained that a sample calculation of one of the sites should be shown in the appendix report so the method of arriving at the costs is known. Details of all sites considered would be too bulky.

D. It was noted that the Navajo generation (three 800-mw units) 1975 estimated cost was up to $230/kw (with scrubbers) which is comparable to NCPS costs.

E. A paragraph will be added to the Thermal Generation report concerning the increased cost of using dry-type cooling. The actual costs will not be included in the total NCPS costs but the discussion will indicate the effects of using dry-type cooling.

F. Ed Glass will write a paragraph for consideration concerning the use of 3.463% interest for the pipeline.

G. The subject of air pollution in connection with Secretary Morton's recent construction moratorium in Arizona was discussed but was deferred for more discussion tomorrow at the Coordinating Committee meeting.

The Study Manager distributed copies of the June 13, 1971, Billings Gazette article on the NCPS (copy attached).

The next meeting of the Steering Committee will be at 9:30 a.m., August 18, 1971, at the Airport Holiday Inn, Denver, Colorado.

June 23, 1971
Approved Statement

"At the suggestion of the Steering Committee, a brief analysis was made on the comparison of moving generation from the Gillette-Colstrip site to a Beulah, North Dakota, site. This study was made only at the 3,000-mw generation level, changing the entire 3,000 mw from one site to another, using the same system loads and load points and obtaining the same transmission system reliability. Under the prescribed conditions, it was found that the additional cost of generation (higher coal and generating equipment) at the North Dakota site was higher than the savings in transmission. It was realized that it would perhaps be more practical to: (a) use a combination of generation at the two sites, or (b) serve certain individual or groups of entities from the North Dakota site alone; however, it was not feasible because of limited time to study such combinations in this initial phase of the study and could possibly be fully investigated in phase II or outside the scope of the North Central Power Study."

The Billings Gazette Sunday, June 13, 1971 Morning Edition

Our coal most feasible

By DAVE EARLEY
Gazette Staff Writer

Mine-mouth generating plants expected to turn the coalfields in a five-state area into large amounts of electrical energy are most feasible in the Colstrip-Gillette "oval."

This is a to-date conclusion of the North Central Power Study in its final stages by a consortium of public and private power distribution companies.

Beulah, N. D., was considered as an alternative during earlier stages, says study manager Bill Graham.

But longer transmission lines between the Montana-Wyoming

DAVE EARLEY

area and Midwestern power markets will be cheaper in the long run, it was decided, than the shorter lines which would be necessary to connect Dakota fields with the market.

The difference is in the coal and its relation to the cost of heat.

SUBBITUMINOUS COAL in the oval surrounding Colstrip, Mont., and Gillette, Wyo., burns hotter than the lignite of the Dakotas. This results in a lower cost per BTU (British Thermal Unit, a measurement of heat).

In the oval, planners found, the range is 11-13 cents per BTU; in the Dakotas 12.5-14 cents; in Colorado, 15-20 cents.

NCPS was conceived about a year ago. And the actual study began in September with a target date later this year for completion of initial planning work.

After that, phases two and three will include decisions by member power distrbutors concerning whether they wish to participate—and construction.

The prediction is that coal in the five-state area could by converted, more or less on-site, to 240,000 megawatts of electricity—enough to light up 2.4 billion 100-watt light bulbs.

Currently, the coal is strip-mined and shipped via railway to generating plants in the Midwest—but 500 or 750 kilovolt transmission lines, once emplaced, might be cheaper in the long run than eternal dependence on the railroads for bulk shipment of coal.

BURN THE COAL right at the mine mouth, say the planners, to heat water to turn generator turbines—and "ship" the electricity.

Membership in the 13-state consortium, which includes not only the coal-bearing area but the potential market areas, includes 19 investor-owned power companies (including Montana Power and Montana-Dakota Utilities), 6 co-ops (including Basin Electric), two public power districts and representation from some 750 municipal power systems in the area.

All the "basic" work is done, says study manager Graham who, as regional power supervisor for Bureau of Reclamation, is the only federal member in the study group.

"Now we've got to find out what we've got."

Data has been collected, decisions such as whether to run cost analyses on both Colstrip-Gillette and Beulah have been made, and the analyses themselves are completed—and now the various committee reports are under way.

Selection of the Colstrip-Gillette oval for study purposes does not rule-out plant construction at other sites, Graham says. The area just seems best for basic planning.

If power companies in the Minnesota area found it necessary, for example, a plant could be constructed in North Dakota. But NCPS is concerned with the whole Midwest market area, including cities as far south as St. Louis, Mo.

From the latter city, the increased length of transmission line to the oval, compared to Beulah, is not enough to compensate for the difference in heat-price.

OTHER PROBLEMS considered in the study, so far, include the question of whether the proposed Montana-Wyoming transmission network should include an east-west intertie: should east-bound transmission lines from the oval be connected with the west-coast power grid?

Presently, there are interties at Fort Peck, Yellowtail Dam and Stegal, Neb. The liability in interties is that they cost more money and there is a danger of energy surges.

In a manner of speaking, energy "seeks its own level" the way water does. If a locality in the Midwest or East experiences a power shortage, electrical energy from the west surges over the line to fill the "vacuum." The surge can damage the system.

A leased telephone line for warning, and what amount to circuit breakers, now protect the three interties in this area.

Planners haven't decided whether the proposed network should contain an east-west tie.

Other problems include the environment—which usually costs more when construction is contemplated.

Thermal generation will involve a virtually closed system, says Graham, so water pollution should not be a problem.

Other questions remain: transmission towers, their type and location; strip-mined land reclamation; and air pollution.

PRELIMINARY estimates are that 20 per cent of the transmission towers will be of the "pretty" type, rather than the lattice-work towers usually erected because they cost less.

Lines will be routed around mountains rather than over them, the study manager con-tiues, to ease the aesthetic strain on those who live near them.

Complete reclamation of mined land is planned. And the matter of electrostatic precipetators to remove sulfur from the air is yet under discussion.

One bonus for planners is that the local coal—while not of as high grade as eastern anthracite—has a low sulphur content.

42. <u>Coordinating Committee Meeting - June 24, 1971, Sheraton Inn, Denver, Colorado</u>.

Chairman Swanson called the meeting to order and commented on the excellent progress being made on the study with special emphasis on the wonderful cooperation being obtained from the committee and task force members. He then asked for comments on the fifth progress report and received none.

The Study Manager made a detailed report on committee as well as task force work progress and other items discussed at the Steering Committee meeting the previous day (see section 41). The schedule for future work and meetings was given as follows:

a. First draft of summary report (Volume I) to be sent to the Steering Committee and working chairmen by August 1, 1971.

b. Working chairmen have comments to Study Manager by August 10.

c. Steering Committee meeting to review report August 18.

d. Mail report draft to Coordinating Committee members in time to review before next Coordinating Committee meeting the first half of September.

The Study Manager also reported that it appears that only about $8,000 would be spent on computer time so it looks like each Coordinating Committee entity would receive about $1,200 refund from the $1,500 deposit made earlier.

The Chairman asked John Bugas to summarize the background on the 1-year moratorium on construction of large thermal plants in Arizona. In the discussion that followed it was emphasized that the North Central Power Study should very definitely cover the air pollution problem in detail and perhaps even make recommendations concerning future research on this subject. It was pointed out that the second phase of the North Central Power Study would have to deal with environmental problems in more detail than phase I. The following action is to be taken as a result of this discussion:

a. Emphasize the positive aspects of pollution control which will be included in the NCPS.

b. Have individual Coordinating Committee entity environmental staff members review the report for environmental impact.

c. Harold Aldrich check with the Department of Interior concerning any possible conflicts in issuance of the NCPS as planned with respect to the recent Arizona development.

The Chairman then proposed a resolution be adopted using $1,000 of unused computer money to set a meeting of the Steering Committee and committee chairmen to do the final review in a more relaxed atmosphere. When it was pointed out that the money could only be used for computer work and that all the Coordinating Committee members must okay any change, it was decided not to pursue this proposal further.

The question of how many reports will be printed and who would get copies was raised. This will be discussed by the Steering Committee at its next meeting. The color of the report cover and type of binding will also be discussed.

43. Steering Committee Meeting - August 18, 1971, Airport Holiday Inn, Denver, Colorado.

All Steering Committee members were present at the meeting as well as the Chairmen of the Report and Economics Committee. The following report was given by the Study Manager.

a. Reports. There will be 1700 copies of Volume I and 1200 copies of Volume II printed. One copy of each report will be given to all Coordinating Committee members (including the 750 municipals), to all people who were on committees or task forces. The remaining copies will be sold for the publishing price to anyone who desires copies. Reports will be mailed between 5 to 10 weeks after the Coordinating Committee approval.

b. A check by Aldrich of Interior's comments on publishing the NCPS report in view of the recent Arizona developments resulted in the comments that there should be no conflict and the NCPS report should be published as planned.

c. The Study Manager recommended that a press release be drafted which could be used as a basis for all entities to make individual releases at a simultaneous time when the report is issued. The Steering Committee directed Ralph Shaw to prepare the release for approval at the next Coordinating Committee meeting. It was also suggested the Study Manager give advance information from the report to *Electrical World*, if requested, on the condition the information not be released until after the report has been mailed to the Coordinating Committee (say the December issue of *Electrical World*).

d. A refund of $1,410.49 will be mailed to 27 members and $1,410.50 to 9 members in about 2 weeks. The reason for such a large refund out of the $1,500 assessment was because stability studies were not run on the computer and also the Western transmission system was only hand calculated.

e. Comments on the August 1 draft of Volume I were received from nine people, and these comments have been incorporated in the master draft of Bill Lloyd, Chairman of the Report Committee.

f. The Steering Committee agreed with the Study Manager's suggestion that the Volume II report be published without draft approval since it will be about 500 pages, and also the report will be as submitted by the Committees and Task Forces with only minor additions or deletions. A note to this effect will be included in the Volume II preface.

g. The Steering Committee approved a transmittal letter draft to accompany the Volume I report submitted by the Study Manager. Stan Swanson will sign the letter as Chairman of the Coordinating Committee.

The rest of the meeting time was used for review of the August 1 draft of the Volume I report. Numerous changes were made which will be incorporated in the September 1, 1971, draft. Changes were mostly in concept or content rather than minor editorial details.

The Steering Committee set the next meeting of the Coordinating Committee for September 24 in Denver. With the final report draft to be mailed on September 1, it was hoped that Coordinating Committee members will have adequate time to review the draft and to give approval to publish, with changes if desired, at the September 24 meeting. Stan Swanson will invite Assistant Secretary James R. Smith to attend the meeting as this may be the last meeting of the group as now constituted.

There was a detailed discussion on the idea that the report was a compromise of ideas of various entities and that it was known that no one entity agreed with all the concepts used in the study. This thought will also be included in Volume I so the reader of the report will understand.

44. Coordinating Committee Meeting - September 24, 1971, Airport Sheraton Inn, Denver, Colorado.

Chairman Swanson welcomed five people at the Coordinating Committee meeting and gave a brief review of progress to date. He stated he was presently surprised that the study had gone forward at such a rate and that the cooperation shown by all parties was certainly appreciated.

Ed Glass, on behalf of the Steering Committee, presented the Study Manager with a present as a token of their appreciation of his work during the last year and in the hope of "improving his appearance."

The Study Manager gave an illustrated presentation showing the history of the study, the results of the study, and some of the drawings and tables which will be in the final report. He also presented the following information:

1. Refund checks had been mailed on August 31 of $1410.49 and $1410.50 to the 36 Coordinating Committee entities.

2. He described the publication and availability of both Volumes I and II. Each Coordinating Committee member and each person on an NCPS Committee would receive one copy of each report. Additional copies of the report would be available at publishing costs which are estimated at this time to be $1.50 each for Volume I and $2.50 each for Volume II. It will take about a month from approval before the reports can be mailed.

3. Volume II would not be mailed to the Coordinating Committee in draft form but would be issued as submitted by the working committees (with minor corrections and additions) and a statement would be inserted in the preface stating the volume was being issued under these conditions.

4. If the Coordinating Committee approved publication today, the reports would be mailed about November 1, 1971. Also one more (the 6th) Progress Report would be issued soon.

The next item on the agenda was the September 1 draft of Volume I. The Study Manager explained the changes already made and other comments by various entities. Bill Talbott (Montana Power Company) resolved and Bob Asheim (Black Hills Power & Light Company) seconded that the report be issued with appropriate changes as discussed. After discussion the motion was passed unanimously. Included in the discussion was the desire to put an environmental statement in the introduction and to put Assistant Secretary of the Interior James R. Smith's May 26, 1970, statement in Volume II.

The Coordinating Committee gave the Steering Committee authority to redraft a press release to be issued when the report is published. Chairman Swanson will send the release to all Coordinating Committee members and specify a release date so all entities can make simultaneous release. The release will have more technical and environmental material than the draft presented. Ralph Shaw will redraft the release and mail it to the Steering Committee for comments.

A motion was made and passed that the Steering Committee be commended for its work in guiding and overseeing the study. The Study Manager expressed his appreciation to all the Coordinating Committee members for their support and work in completing the study.

Meeting adjourned.

DEPARTMENT of the INTERIOR

news release

For Release to PM's, May 26, 1970

REMARKS BY JAMES R. SMITH,

ASSISTANT SECRETARY - WATER AND POWER DEVELOPMENT,

DEPARTMENT OF THE INTERIOR, WASHINGTON, D. C.

TO MAJOR ELECTRIC POWER SUPPLIERS OF

NORTHCENTRAL UNITED STATES,

OMAHA, NEBRASKA, MAY 26, 1970

Never before in the history of our Nation has there been as much need for broad, imaginative and sophisticated approaches to the task of providing adequate and reliable electric power for our citizens. We live in a power-oriented society. We accept electricity as a necessity--not only in our homes but on our farms and in industry and commerce. We take electric power so much for granted that when we are occasionally deprived of it - even for a few hours - we are stunned at our dependence on it. Our civilized society comes almost to a complete halt when we suffer a major power failure such as occurred in the Northeast in 1965 and in the Midcontinent area in 1966.

This very summer certain portions of the country may reap a bitter harvest in power curtailment. If it happens, the brownouts will be the result of decisions made half a decade or more ago. It is not my purpose to place blame on any segment of the electric industry or on any governmental entity, local, State or Federal - or for that matter the silent majority or the vocal minority. No purpose would be served and the subject is too complex for quick and easy analysis.

I would make the point, however, that the electric industry will be hard put to find excuses if it does not take full advantage of past experience and utilize every resource at its command to prevent a year after year recurrence of power shortage problems.

This Nation's energy requirements are considered to be doubling every seven to ten years. The American people will demand sufficient electricity for their needs. I do not believe that this Nation will accept a static or a regressive society in which our citizens are expected permanently to curtail their use of electric energy.

Thus a massive burden is placed on the power suppliers - to plan together, to build together and to finance together, and to distribute power in such fashion that this Nation's power requirements will be met. We have already passed the point in time when small differences can be permitted to intrude on this overwhelming public obligation.

You gentlemen represent the major power suppliers in a vast area from the vicinity of Chicago westward to the Continental Divide and from the Canadian border halfway to Mexico. The area as shown on this map comprises all or parts of 17 States and even a portion of South Central Canada.

This is not only a vast area geographically but an area of population and economic growth. Population will more than double in the next half century and economic growth and stability must keep pace. The region contains such metropolitan areas as St. Louis, the Kansas Cities, Omaha-Council Bluffs, Denver, Salt Lake City, Minneapolis-St. Paul and a host of smaller communities. It also contains areas with a population density of less than one person per two square miles. There are numerous subregions with wide diversities in climate, resources, economics, social structure, agriculture, manufacturing and other factors.

However, there is one common and essential need in the entire area--ever-increasing amounts of reliable electric power at minimum cost.

This is an area in which the Federal Government and both investor-owned and publicly-owned utilities have played major roles in supplying power requirements. The Federal Government has a large investment in hydroelectric generating facilities and wholesale transmission systems.

Both hydro and thermal power play important roles. In the Missouri River Basin approximately 28 percent of the generating capacity is hydro and 72 percent is thermal. In the eastern portion of the region, the capacity is principally thermal.

As we move into the decade of the 70's, the major power suppliers, and I include all of us -- the Federal Government, the cooperatives, the utility districts, the municipals and the investor-owned utilities -- must work together more effectively if we are to fulfill our responsibilities to our customers, to the region, and to the Nation.

Decisions of the 50's and 60's regarding power supply and transmission were made in much simpler times. Compared to today they were easy. A host of new factors have been introduced into the decision-making process. If for no other reason, these new factors require an infinitely higher degree of coordination and cooperation than has ever been faced in the past. Let me cite a few of these factors:

For the first time in our history the very real problem of irreparably harming our natural environment has captured the attention of our citizens. The problems of powerplant siting--both thermal and nuclear--have become extraordinarily difficult. The American people will no longer accept any appreciable amount of thermal pollution of our streams and lakes. The American people will no longer accept any appreciable degree of air pollution.

In the matter of transmission lines, aesthetics and environmental considerations add to the problem of providing adequate and reliable power for a growing population.

These new considerations will cause ever-increasing, nonproductive costs in terms of low-cost power. They will have to be borne by someone - the rate payer, the cooperative member, the stockholder, or the American citizen generally. But regardless of who bears the ultimate cost of providing reliable power under today's rule book, it is incumbent on every power supplier and bulk power distributor to minimize those costs to the consumer by a greater degree of joint planning and cooperation than has ever before been necessary.

Fortunately there are counterforces which work to assist in minimizing these necessary environmental and pollution costs. The technology of the electric industry is moving forward rapidly. Not many years ago a 100-megawatt plant was considered large. Today 1500 to 2000-megawatt plants are on the drawing board and under construction.

Not too many years ago a 69-kv or 115-kv transmission line was considered quite sufficient and in some cases extraordinary. Today we are considering--or should be--a backbone transmission grid for this region of 500-kv and higher.

The technology of direct current transmission is being perfected. Although expensive, it permits the transmission of electricity for vastly greater distances in vastly greater amounts on fewer wires which intrude infinitely less on the environment.

Thus we are increasingly able to generate more power at substantially less cost per kilowatt, and to transmit that energy over far greater distances.

These, in broad general terms, are the compelling reasons why it is more important to undertake total joint planning today than ever before.

But we need to go further than that. We need to get down to the specifics of action. That is why I want to discuss the power study which the Department of the Interior proposes for this region and to explain why I believe it to be the responsibility of my office to assume a leadership role in that study.

In this region, the Department of the Interior, through the Bureau of Reclamation, markets power from all of the dams on the main stem of the Missouri plus several major tributaries. The Federal Government has built and operates nearly 10,000 miles of the backbone transmission grid in the region.

Under law the Federal Government has a direct responsibility to the preference customers in the area, as well as an indirect responsibility -- as a major Federal agency -- to all of the citizens in the region irrespective of their primary source of electric power. The Department of the Interior sells power to virtually every power supplier and distributor in the region.

Interior has a responsibility to the citizens and to the Treasury to make the most effective possible use of Federal generating and transmission facilities. This imposes on the Department an obligation to insure that Federal generating and transmission facilities are melded with non-Federal electric facilities in the most effective manner.

Secretary Hickel calls this "the responsibility of ownership," and I subscribe fully to the Secretary's feeling of obligation. The Federal Government is, and will continue to be, deeply involved in power marketing. We are in a position to, and should, provide leadership but certainly not dominance.

With that assessment of the Federal obligation and role in helping to provide reliable electric power to this region, it seems essential that my office, through the Bureau of Reclamation, encourage adequate, minimum cost, reliable electric energy and the optimum development of the natural resources of this great midcontinent region.

In order to accomplish this, I am ready to commit Interior to spearhead--but not to dominate--a broad gauge study of the future power requirements in this area and the best methods of meeting those needs.

This will be no simple task. We expect it to take a year. We are willing to provide at least 50 percent of the man-hours required to accomplish the task. We are willing to provide technical and professional guidance. But we cannot succeed alone.

Success will depend on the full cooperation and participation of all the major power suppliers in the area. We shall use all of the wealth of information, data and thought which has resulted from the excellent studies which have been accomplished to date. It would be wasteful of Federal and private funds to be redundant with or to duplicate that which is already accomplished. But I foresee this study going one step beyond where we are now -- looking into the future and painting with a broad brush. We must use innovative and imaginative thinking to make this region a model for the rest of the United States in providing adequate, reliable and minimum-cost power.

In broad terms the study which we propose will deal with five aspects:

1. We will develop an accurate projection of the area's future economic base, including: population - how many people and where; the economy - agricultural, commercial and industrial, and the other factors which can give us a picture of the future of the region.

For this purpose we will make maximum use of the so-called "Framework" or "Type I" comprehensive study which is about to be completed by the Missouri Basin Interagency Committee at a cost of more than $6 million.

2. We will develop an accurate picture of the projected power needs of the Region for the next 20 or more years. We must project how much those needs will be in the aggregate and where those loads will occur. Equally important, we need to know the rate at which demand for electric energy will grow and the capability of generating electricity for occasional export to adjacent areas.

3. We will ascertain where additional generating capacity should be located in order to make the most efficient use of our resources and technology to obtain reliability of service at lowest cost. A study of future generation and the associated economics thereof requires a study of the coal and lignite resources of Montana, Wyoming, North and South Dakota and the availability of water necessary to complement those massive fuel resources. Reserves are estimated in the trillions of tons. The Office of Coal Research has indicated a willingness to cooperate in defining and analyzing these reserves and their potential in meeting future power needs.

4. We must assess the future role of the hydro facilities in the main stem Missouri River Dams. It is generally conceded that the most efficient use of hydro energy is for peaking rather than load factor power. As this area, in order to meet its growing demands, becomes more and more dependent on thermal generation--nuclear or fossil fueled--the role of hydro energy will become more and more valuable as a peaking operation.

According to the Corps of Engineers the power peaking capability of the mainstem dams can drop about 4 percent between now and 2020 as upstream depletions increase. The system's available energy could be reduced as much as 37 percent for the same reasons. Since peaking capability levels can be virtually maintained, the hydroelectric capacity probably should be increasingly converted to peaking use.

The Corps will initiate studies during the next fiscal year to determine the ability of the mainstem system to provide additional peaking capability. Should it be found economically and engineeringly feasible, I would hope that all of the major power suppliers in the Region both public and private would support the installations of added capacity at the existing dams.

5. We must overlay on present transmission facilities the additional transmission necessary to connect present and future generating sites to load centers and to interconnect with other area systems for mutual benefit.

Determination of the location and size of future generating capacity and associated transmission facilities should be done irrespective of ownership. I indicated earlier that among the needs for joint planning is the need to build and finance jointly. Surely, we can find a way in this area, as has already been done in the Pacific Northwest and Southwest, to construct maximum size facilities, on a joint venture basis, forgetting political considerations, in order to obtain maximum economic benefits of our customers.

6. There are a number of "spin off" values in the type of study which we envision. Various energy companies are acquiring coal leases and water supplies to develop coal resources in the western Missouri Valley. Oil companies, mining companies, and others are looking to the extraction of hydro-carbons: gasoline, natural gas, fuels, dyes and other chemicals from coal.

These processes need refinement. They also need water that can only be moved by pumping plants requiring electric power. Prospects are good that products from the hydrogenation of coal will be on the market within a decade. There is a synergism involved here. The by-products of coal gasification and hydrogenation can provide boiler fuel for the generation of electric energy. We must determine the values of that type of coordination in the energy field.

Finally, we must recognize that if we plan properly, carefully, and jointly there will be times when this region will have excess power to export or can use power available for import from another region. For that reason I have asked the Administrators of the Southwestern and Bonneville Power Administrations to sit in on this meeting, to keep continuously abreast on the study which we are undertaking and to provide such information as we can use in determining amounts, timing and availability of such markets on movements.

Let me conclude then by summarizing. Tremendous amounts of power will be needed in this area in the next two decades. The major power suppliers--including the Federal Government--have the responsibility to the public to use their best efforts to meet those needs. Hydro and thermal power must be produced and blended in the most economic way. Not far north and west of here lie some of the largest fossil fuel reserves in the world. The electric industry and other energy interests can complement each other in extracting and using the hydrocarbons in the vast resources in Montana, Wyoming, and the Dakotas. We have the technology to continue to develop transmission facilities necessary to serve needs of the region. While accomplishing these purposes, we must protect and enhance the environment in which we live.

All we need is the willingness of our major power suppliers to address themselves to the task. I can promise you the full cooperation of the Department of the Interior. We will provide the manpower and leadership to meet our responsibilities. We will go the full route--and one step more to assist in cooperative planning to meet the future power requirements of the area.

We ask your help and we ask your participation in this great step forward.

First we need a management commitment to cooperate and participate. That commitment can be best expressed by cooperating in the plan of action which we develop and agree upon during the remainder of this meeting.

X X X

II. Criteria

Detailed criteria that were used in the study can be found in the individual reports of the Committees and Task Forces. This section lists some of the correspondence which dealt with overall criteria which were approved by the Steering Committee. Given below is a list of the contents of this section:

1. Scope and General Guidelines - 9/3/70
2. Committee and Task Force Guidelines - 9/3/70
3. Phase letter - 11/13/70
4. Reliability letter - 11/19/70
5. General letter - 2/2/71
6. Transmission letter - 3/4/71
7. General letter - 3/12/71
8. Costing Plan - 3/12/71
9. General letter - 4/6/71
10. Flow Chart - 10/19/70
11. Study Time Table - 9/2/70

Revised 7/29/70
Revised 8/13/70
Revised 9/3/70

STUDY SCOPE AND GENERAL GUIDELINES

I. Purpose - The purpose of this study is to promote coordinated development of electric power supply facilities in the North Central United States. Specifically the study will investigate the practicality of developing an economical, reliable, and environmentally oriented generation and transmission system designed to utilize the fuel and water resources in this region. Through coordinated efforts between water, power, and fuel suppliers, it is hoped joint economies to the participants and the ultimate consumer may be achieved.

II. General Plan of Study - The general plan for the study is to have the working committees and task forces develop all the required information to determine the feasibility of installing large generating complexes in the coalfields of the study area. It is planned that existing information from the many individual utility and pool studies will be utilized to the fullest extent. Various alternatives will be studied and cost data developed. For example, plans composed of thermal generation of various capacities such as 1,000 mw, 3,000 mw, 5,000 mw, 10,000 mw, etc., integrated with hydro peaking with various delivery points will be investigated. A three-step program is anticipated; (a) the initial study as outlined in the preceding sentence, (b) having each utility determine its level of participation in various plans, and (c) determining a practical level of development and implementing for actual construction.

III. Participation - Study participants will be from a wide geographic area covering the Missouri River Basin and adjacent areas. Any major electric power organization constituted to purchase and sell power within this area can be represented on the Coordinating Committee. Smaller entities may be represented on a group basis with the approval of the Coordinating Committee.

The Steering Committee will suggest appointments to Committees and Task Forces for approval of the Coordinating Committee. Background and experience in similar studies will be considered in making appointments to the various task forces. Any individual desiring to do so may be designated to serve on the working task forces; provided that he can make a contribution to the study.

As soon as the Coordinating Committee has approved assignments, study scope and guidelines, working groups will meet with the chairman of the Coordinating Committee, the Steering Committee, and the Study Manager to discuss and further establish assignments.

Observers will be welcome at Coordinating Committee meetings. Periodic status reports will be prepared and made available by the Study Manager to all study participants and to others who may request them.

The participants, in line with existing responsibilities, will provide required coordination and liaison with State, local, and other Federal offices.

IV. <u>Timing</u> - The study is to be completed as expeditiously as possible. the goal is to achieve publication of the final report in approximately 1 year from initiation of work by the task forces.

V. Area to be Studied - The study area will include all or parts of the States of Utah, Colorado, Wyoming, Idaho, Montana, North Dakota, South Dakota, Nebraska, Kansas, Iowa, and Minnesota. Inclusion or not of the complete power systems of boundary line participants will be made at the discretion of the concerned committees and the individual participant. As the study progresses, entities outside the immediate study area may be included if it is found desirable or necessary to do so.

VI. Years to be Studied - The study will encompass the period from 1978 to 2000. Initially, for data gathering and analysis purposes, the years of 1980, 1985, 1990, and 2000 will be investigated.

VII. Fuel Suppliers Participation - Representatives of the fuel suppliers (coal, oil, gas, etc.) will be encouraged to work with committees dealing with coal and water as well as other associated work groups.

The Coal and Byproducts Task Force in addition to gathering detail on coal will be interested in coal byproduct fuels for thermal powerplant use.

VIII. Computer Studies - Detailed computer studies will be performed to test the adequacy and reliability of planned transmission system facilities, and to determine generation reserve requirements.

Power flow, classical stability and probability programs will be utilized in these determinations. The East-West ties will be assumed open for preliminary studies; therefore, the Bureau of Reclamation can use its existing power flow and stability computer programs. If it is later determined that dynamic stability cases should be investigated, the Coordinating Committee will be so advised and consideration will be given to obtaining the required program and necessary finances.

IX. East-West Ties - For purposes of this study, and as noted above, the East-West ties will be assumed open; however, it is recognized that later studies dealing with the E-W tie problem may be required.

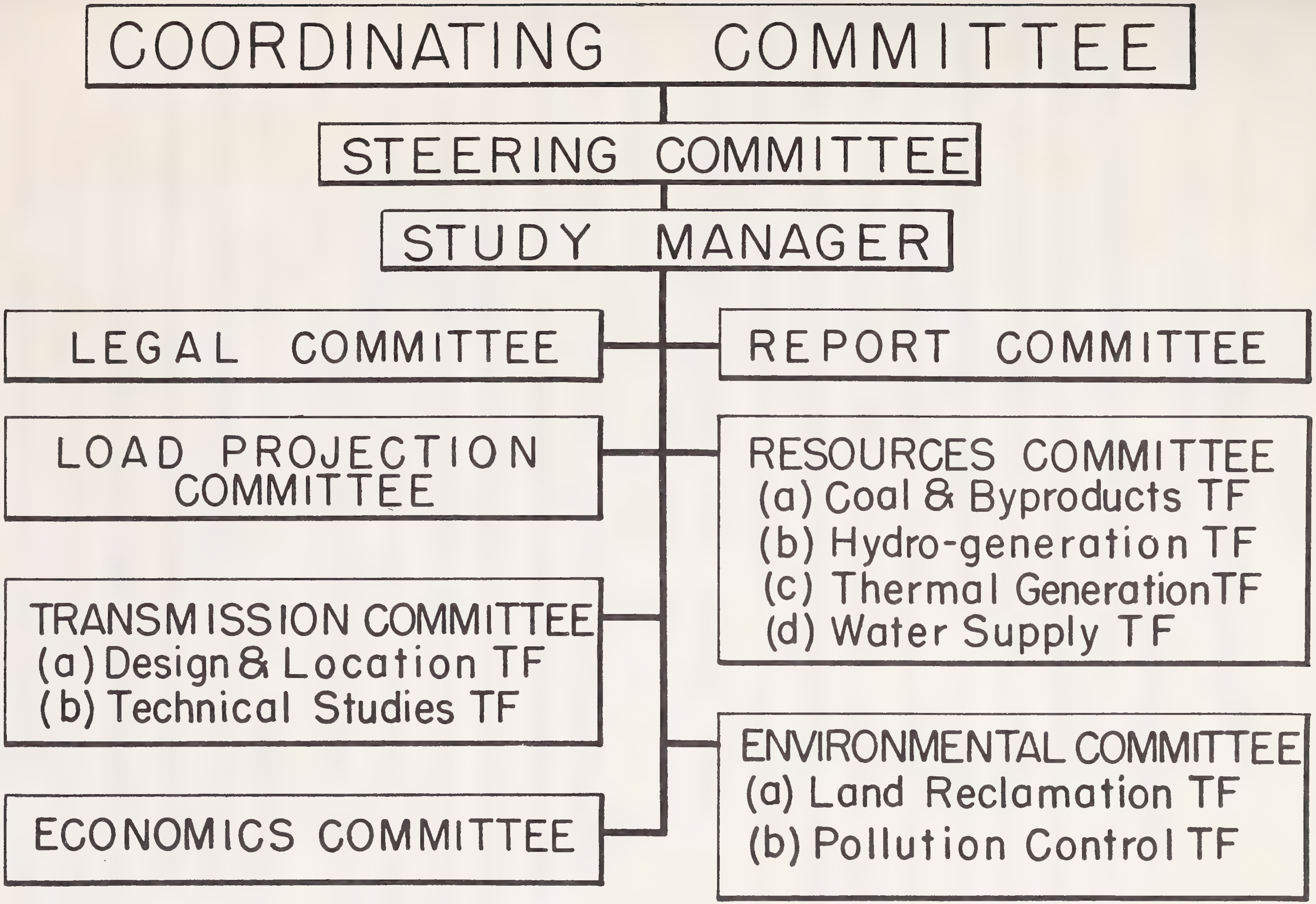
X. Study Organization - The attached chart shows the basic organizational alignment to be used for this study. All committee chairmen will report directly to the Study Manager who, in consultation with the chairman of the Coordinating Committee and with the Steering Committee, will coordinate the work of the committees and provide liaison with the Coordinating Committee. Task forces will report to the chairman of their basic committee. Committee chairmen in consultation with the Study Manager will determine whether changes in task forces are desirable as the study progresses. These changes must be approved by the Steering Committee.

XI. Alternative Power Cost Comparisons - The study will be conducted on the basis of deriving the costs of delivering power and allowing individual entities to determine whether these costs compare favorably with their alternatives. Sufficient details of the economic derivations will be included in the final report so that practical comparisons can be made.

XII. Final Report - The final report will be issued as a group report. Sufficient copies will be made for general distribution to all interested parties.

XIII. Study Costs - With the exception of the computer studies, study costs will be limited to personnel expenses and travel costs which will be borne by the individual entities. Assuming only the need for probability, power flow and classical stability studies, actual computer rental costs shall not exceed $50,000 which will be equally proportioned among the participants on the Coordinating Committee. Costs of publishing and mailing the final report as well as progress reports will be assumed by the Government.

The report will be printed on standard 8½" x 11" paper as a report by the participants and not as a Federal report.



TF = Task Force

Rev. 8-10-70

June 29, 1970
Revised August 13, 1970
Revised September 3, 1970

Committee and Task Force Guidelines

I. Coordinating Committee

The Coordinating Committee through the Steering Committee has the basic responsibility of providing management surveillance and insuring that the study is completed expeditiously and realistically. The Committee's responsibilities can best be accomplished by holding periodic meetings as required, and having the Steering Committee report on the study progress. These sessions will provide opportunity for reassessment of study course and objectives. If the occasion should arise where a problem cannot be settled within the Coordinating Committee, it shall be referred to the "President's Committee," established and headed by the Assistant Secretary for Water and Power, for resolution.

II. Steering Committee

The Steering Committee through the Study Manager will give overall coordination and guidance to the various working committees. The Steering Committee will hold periodic meetings as required with the committee and task force chairmen as the study progresses. The Steering Committee will report directly to the Coordinating Committee.

III. Study Manager

All committee chairmen (excepting Coordinating and Steering Committees) will report directly to the Study Manager who has the responsibility of: (a) Generally directing the efforts of the individual committees, (b) achieving coordination among committee groups and maintaining the continuity of the study, (c) preparing and disseminating status reports, and (d) providing liaison between committee groups, the Steering Committee, and the Coordinating Committee.

IV. Legal Committee

It is the responsibility of the Legal Committee to investigate legal aspects and develop solutions to enable the successful implementation of proposed developments. Ownership of facilities outside a utility's operational area, possible ownership arrangements, and arrangements for exchanges of energy and capacity both on long term as well as short term are examples of subjects which must be investigated. The Legal Committee will develop and draft contract forms which will enable implementation of proposed developments.

V. Report Committee

It is the responsibility of the Report Committee to prepare the study report for publication. The basic duties of this committee will be to utilize the rough drafts prepared by the various committees and task forces and edit, revise, and combine them into a finished report.

VI. Load Projection Committee

Electrical loads must be determined by both location and ownership in enough detail for a computer study and also by areas for reconnaissance transmission evaluation. Loads for the study years must be obtained for the prescribed study area. Reference material such as River Basin Comprehensive Studies, Federal Power Commission reports, pool and individual utility data must be reviewed and consolidated. Kilowatt as well as kilowatt-hour requirements by seasons or possibly by months for the years studied must be developed.

In the development of the above load data, consideration must be given to expected population growth and potential industrial developments in the area. Care must also be exercised that loads are not duplicated. Ownership of loads will be as of 1969 with logical distribution of new loads.

VII. Resources Committee

The Resources Committee has the responsibility of combining coal, coal byproducts, hydro-generation, water supply and thermal generation to obtain practical, economical alternative use of resources. In furthering this responsibility, it will coordinate the work of the various task forces under its leadership.

A. Coal and Byproducts Task Force

This task force will compile data on coal deposits relating to tonnage, type, costs and method of mining, costs and method of transporting, processing, firing, and disposition of byproducts within the areas of consideration.

B. Hydro-generation Task Force

Existing baseload hydro-generation will diminish because of other water uses above the plants now in use. Potential future baseload hydro-generation will be minor, therefore, investigation of new hydro will be aimed primarily at peaking installations. The extent of new hydro-peaking capacity will be primarily governed by the total integrated load curve estimates for the study area for any study year. Pumped-storage peaking plants, along with new hydro-peaking plants, will require extensive transmission facilities to enable integration with the thermal loads. The hydro-generation task force should compile potential hydroplant possibilities and provide an estimated cost per kilowatt at the site.

Integration of hydro with thermal can be judged by the relative costs after transmission costs are added.

C. Thermal Generation Task Force

The Thermal Generation Task Force will be responsible for locating, sizing, costing and determining the type of thermal powerplants to be considered in the coal area. Close coordination will be necessary with various other task forces and especially with the Coal and Byproducts, and Water Supply Task Forces, as well as the Economic and Environmental Committees.

D. Water Supply Task Force

This task force must determine the costs and routes for supplying water to the thermal powerplant sites and coal processing plant sites within the study area. Water needs for hydrogenation may exceed those for thermal generation and cooling. Municipal requirements of the towns which will service the plants will need to be estimated. Terminal storage, reuse of water, and disposition of effluents to avoid or minimize pollution will be studied.

The optimum pipeline for future needs should be selected; water deliveries at partial capacity to fit the time frame under study will be analyzed for cost, and electric pumping capacity and energy to move the water into position must be integrated into the cost appraisals.

VIII. Transmission Committee

The basic responsibility of the Transmission Committee is to determine an economical and reliable EHV transmission system. This committee will be responsible for probability and transmission computer studies and will determine reserve requirements as well as transmission voltage, conductor size, terminal equipment, intermediate switching stations, number of lines, and other related data. Coordination will also be necessary with the Economics Committee concerning pricing and annual costs of the transmission equipment.

This committee must also determine transmission system requirements for pumping water to supply the coal sites, to supply construction power for the thermal powerplants, and to integrate new hydro-generation.

A. Design and Location Task Force

This task force will be charged with the responsibility of determining location and basic designs for transmission lines and substations. This task force will coordinate closely with the Transmission, Resources, Environmental and Economic Committees.

B. Technical Studies Task Force

The basic charge of the Technical Studies Task Force is to conduct computer studies to determine the most economical yet adequate transmission system to deliver the generated power to load centers as well as determining generating reserve requirements.

IX. Economics Committee

The Economics Committee will be responsible for evaluating all costs of the power supply plans. Such things as hydro-thermal combination power costs, transmission costs, generation costs (both investment and variable), and water costs must be determined. Much of the cost data will be supplied by and coordinated with other committees and task forces. Economically staged construction must be investigated.

X. Environmental Committee

This committee will coordinate the work of the Pollution Control and Land Reclamation Task Forces. Inherently, this committee will also be consulted on work of other committees and task forces as required.

A. Land Reclamation Task Force

The basic responsibility of this task force will be to investigate various methods of land reclamation and make recommendations for their use. Present methods, proposed methods, as well as new methods should be investigated.

B. Pollution Control Task Force

The Pollution Control Task Force must investigate methods of solving air and water pollution as well as ash disposal to meet Federal and State environmental standards, both present and future. This includes both thermal powerplants and coal processing plants.

July 29, 1970
Revised August 13, 1970
Revised September 3, 1970

COMMITTEES AND TASK FORCES
Personnel

STEERING COMMITTEE

Stan Swanson, Chairman, Iowa Public Service Company
Wm. F. Graham, Bureau of Reclamation
Jim Grahl, Basin Electric Power Cooperative, Inc.
Ed Glass, Northern States Power Company
John Bugas, Colorado-Ute Association
Ralph Shaw, Omaha Public Power District
Dean Bryner, Utah Power and Light Company

STUDY MANAGER - Wm. F. Graham

LEGAL COMMITTEE

R. D. Wilson, Chairman, Nebraska Public Power District
William Wisdom, Basin Electric Power Cooperative, Inc.
Ernest J. London, Bureau of Reclamation
A. E. Bielefeld, Bureau of Reclamation
A. D. Brusven, Northern States Power Company

LOAD PROJECTION COMMITTEE

Larry Stark, Chairman, Public Service Company of Colorado
Howard Easton, Basin Electric Power Cooperative, Inc.
V. J. Dixon, Bureau of Reclamation
Lester Larson, Interstate Power Company

TRANSMISSION COMMITTEE

Harvey Hunkins, Chairman, Bureau of Reclamation
G. F. Walkup, Iowa Power and Light Company
Joe McKay, Pacific Power and Light Company
Charles Cabral, Bureau of Reclamation

TRANSMISSION - DESIGN AND LOCATION TASK FORCE

Charles Cabral, Chairman, Bureau of Reclamation
Joe McKay, Pacific Power and Light Company
R. K. Harbour, Iowa Southern Utilities Company
William K. Graw, Colorado-Ute Association
Stan Fallick, Nebraska Public Power District

July 29, 1970
Revised August 13, 1970
Revised September 3, 1970

TRANSMISSION - TECHNICAL STUDIES TASK FORCE

G. F. Walkup, Chairman, Iowa Power and Light Company
Ted Humann, Basin Electric Power Cooperative
G. G. Worner, Northern States Power Company
Erwin Eggleston, Bureau of Reclamation
Clark Rose, Bureau of Reclamation
W. Ness, Otter Tail Power Company

ECONOMICS COMMITTEE

Leon Barrett, Chairman, Northern States Power Company
Richard Grant, Basin Electric Power Cooperative
L. C. Rassmussen, Kansas City Power and Light Company
Edward L. Leland, Bureau of Reclamation
John E. Droubay, Utah Power and Light Company

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John E. Droubay, Utah Power and Light Company
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Bob Madsen, Bureau of Reclamation
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Tom Gwyn, Montana-Dakota Utilities Co.

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Tom Gwyn, Chairman, Montana-Dakota Utilities Co.
Dan T. Berube, The Montana Power Company
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L. E. Holmes, Bureau of Reclamation, Salt Lake City

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W. S. Kane, Iowa Public Service Company
Bob Madsen, Bureau of Reclamation

July 29, 1970
Revised August 13, 1970
Revised September 3, 1970

RESOURCES COMMITTEE

Howard Ericksen, Chairman, Nebraska Public Power District
W. H. Blankmeyer, The Montana Power Company
Phil Q. Gibbs, Bureau of Reclamation
Thomas L. Weaver, Bureau of Reclamation
W. S. Landers, Public Service Company of Colorado

RESOURCES - COAL AND BYPRODUCTS TASK FORCE

W. S. Landers, Chairman, Public Service Company of Colorado
Herman Dupree, Bureau of Reclamation
Lloyd Ernst, Basin Electric Power Cooperative, Inc.
A. Howard Smith, Office of Coal Research
D. R. Thompson, Omaha Public Power District

RESOURCES - HYDRO-GENERATION TASK FORCE

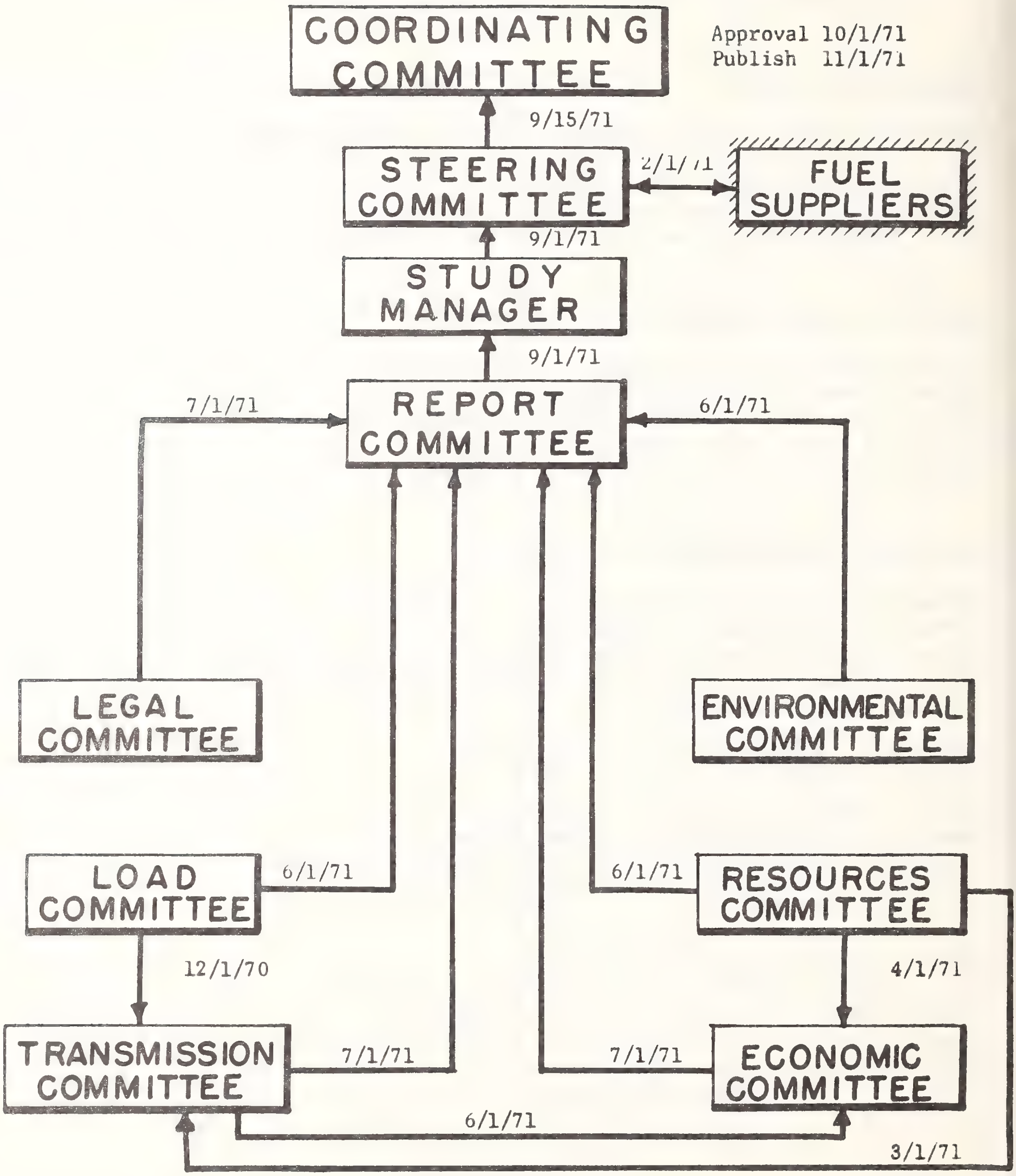
Thomas L. Weaver, Chairman, Bureau of Reclamation
Creighton Bicket, Corps of Engineers
Jerry Cookson, Bureau of Reclamation
Robert J. Marchetti, Minnesota Power and Light Company

RESOURCES - THERMAL GENERATION TASK FORCE

W. H. Blankmeyer, Chairman, The Montana Power Company
George R. Hobbs, Colorado-Ute Association
Tom Christiansen, Iowa-Illinois Gas and Electric Company
, Pacific Power and Light Company

RESOURCES - WATER SUPPLY TASK FORCE

Phil Q. Gibbs, Chairman, Bureau of Reclamation
Harry Baker, Bureau of Reclamation
Ralph Bellamy, Bureau of Reclamation
, Corps of Engineers



DATA AND REPORT TIME TABLE

Dates are latest submission (hopefully earlier--should at least be partial submission before).

United States Department of the Interior

BUREAU OF RECLAMATION
Regional Office, Region 6
P. O. Box 2553
Billings, Montana 59103

IN REPLY REFER TO: 600

To: Coordinating Committee and Participants
North Central Power Study

Gentlemen:

From the number of questions that have been asked concerning the "Stages" or "Phases" of our study, it appears that a clarification is needed and perhaps is overdue. To avoid conflict with staging of construction, "phases" will be used. It is hoped that the following explanation will aid in understanding the overall study procedure. The overall plan consists of three phases with various steps listed below in the order they will occur.

1. Phase I

   A. Step 1. The Resources Committee will arrive at generation costs for various sizes of development such as 5000 mw, 10,000 mw ---- 70,000 mw. These costs must reflect water, heat rate, coal quality and other pertinent factors. Costs of blended hydropeaking power must also be included.

   B. Step 2. The Transmission Committee will arrive at transmission costs for various sizes of generation development. Load centers will be chosen and delivery of our remote generation will be proportioned to the load centers according to relative size of load. Actually, for the base power flow study, the 1980 expected transmission system will be used and loads will be supplied by existing plus planned or additional local generation as required; then the local generation will be backed off when North Central Power Study generation is used. By this method, the Transmission Committee can arrive at costs for reliable transmission for various amounts of power.

   C. Step 3. It must be realized that other committees will be helping on legal, environmental and other considerations. However, the end result that the Economics

Committee arrives at, and which will be in the study report, will be a delivered cost of power for various amounts of generation blocks. An example of the results is shown in Figure 1. It should be noted that the generation cost is expected to be fairly flat while the transmission curve will be sharp and Figure 1 is the total cost. (Figure 1 numbers are purely fictitious and are for illustrative purposes only.)

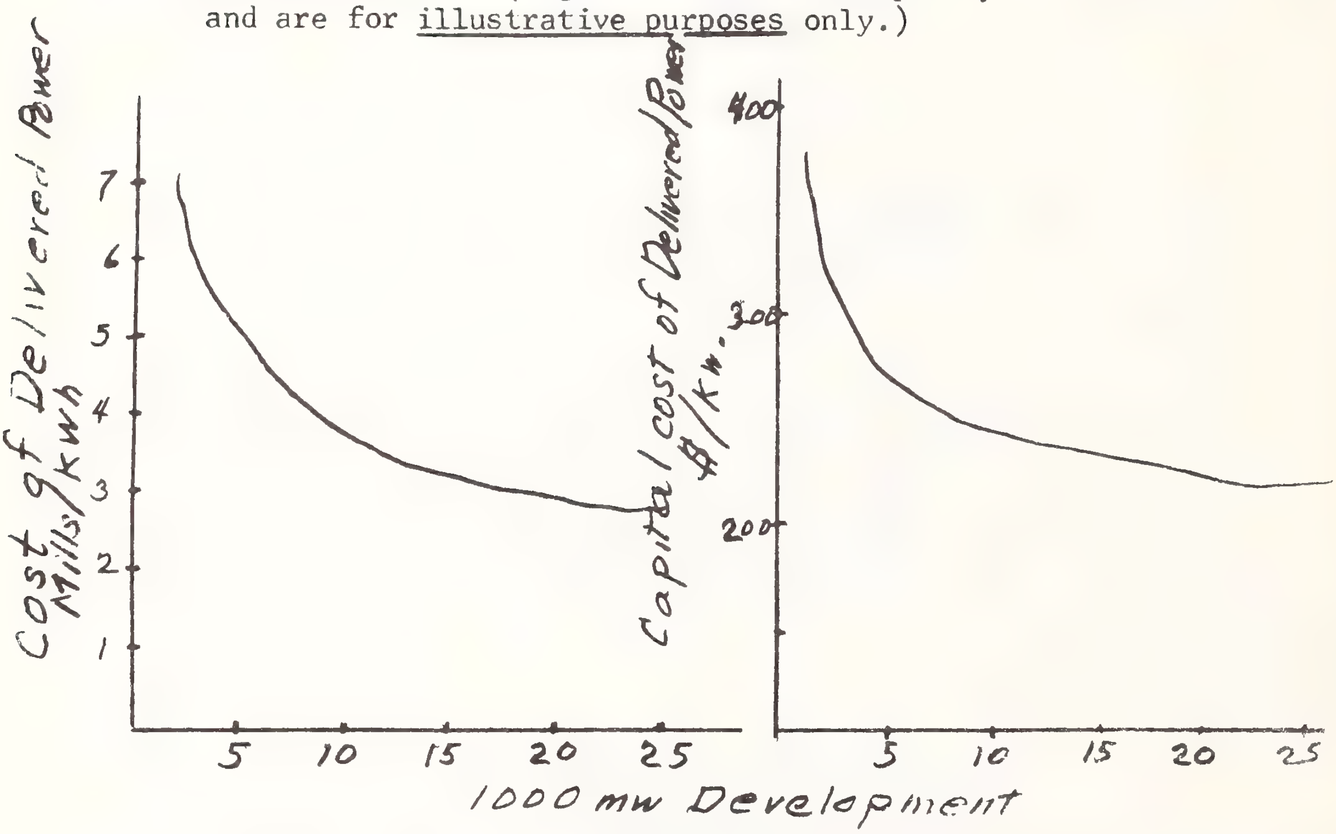


Figure 1

2. Phase II

A. Step 1. The study participants will compare the costs, reliability, environmental and other pertinent factors of this power supply with their alternate sources of power. They will then advise the Coordinating Committee how much power they are interested in, when, and at what location. From the individual requests, we can then summarize the information and develop a curve such as shown in Figure 2.

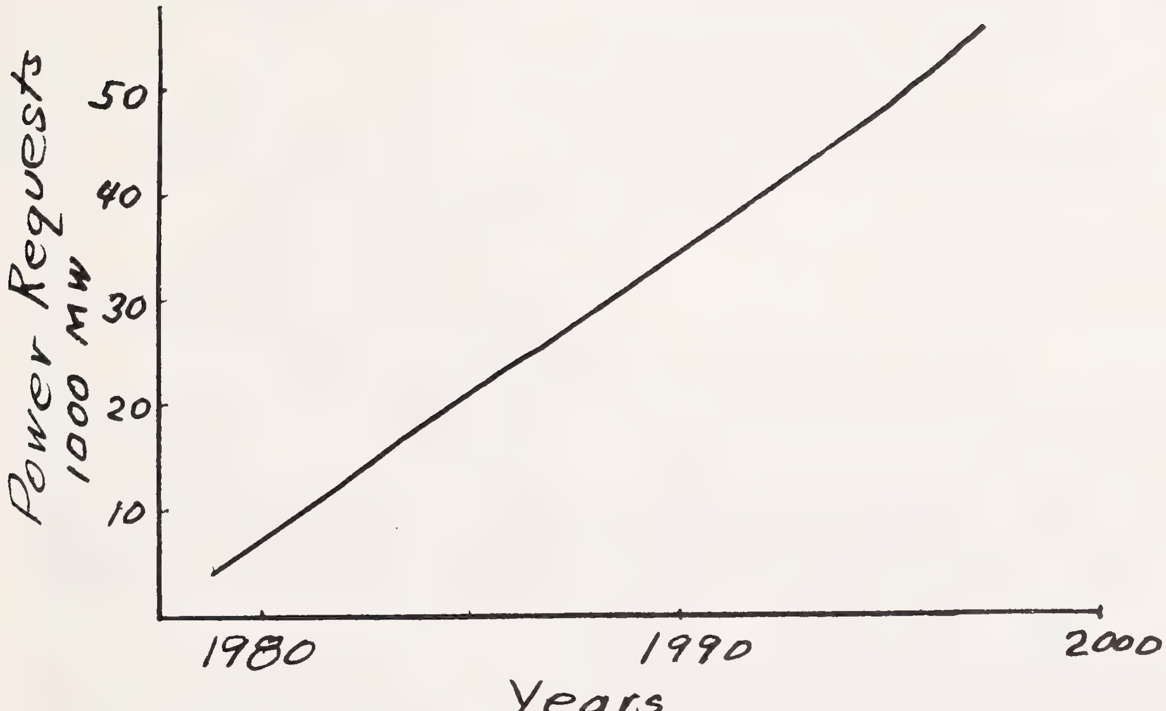


Figure 2

B. Step 2. With the detailed information on power requests obtained from step 1 above, the transmission studies will be redone using actual distribution and magnitude of loads. From these studies a new curve similar to Figure 1 can be developed. (It should be realized that separate curves will have to be drawn for power to the East and to the West. Also the postage stamp rate theory will be used separately for both the East and the West.)

3. Phase III

A. Step 1. Once the cost of power for specific amounts, specific years and specific locations is confirmed by Phase II, it is then time to implement construction of the facilities. Contracts must be made for participation, for coal as well as water supply, and for construction of facilities.

The above summarizes the phases and steps that must be accomplished before this plan can be a reality. Our immediate objective is to accomplish Phase I and publish the results in report form. However, we should all be aware of the overall plan. As can be seen, the load distribution used in Phase I can only be an "educated guess" which must be confirmed or changed in Phase II. By using this method the "percentage of load growth" or the "amount of power by years" served does not directly enter the first phase but rather can be derived only from Phase II.

It is hoped that the above explanation will help in your understanding of the overall plan and how our study is only the basic Phase I part.

Sincerely yours,

William F. Graham

William F. Graham
Study Manager

cc:
Mr. Don Hodel, Deputy Administrator, Bonneville Power Administration, 1001 N.E. Lloyd Boulevard, Portland, Oregon 97208
Mr. Peter C. King, Administrator, Southwestern Power Administration, P.O. Drawer 1619, Tulsa, Oklahoma 74101
Mr. K. Kristjanson, Director of Economics, Manitoba Hydro Commission, P.O. Box 815, Winnipeg, Manitoba

United States Department of the Interior

BUREAU OF RECLAMATION
Regional Office, Region 6
P. O. Box 2553
Billings, Montana 59103

IN REPLY REFER TO: 610

To: Coordinating Committee and Participants
North Central Power Study

Gentlemen:

The minutes of the October 13, 1970, meeting of the Technical Studies Task Force, North Central Power Study, cover discussions on reliability criteria in paragraph 4. The Task Force felt that an effort should be made to comply with both MARCA and WSCC criteria, but there may be stages of transmission system development when full compliance may not be practical. This statement was also repeated on page 6 of the Second Progress Report transmitted November 4, 1970.

An investigation of the meaning of this statement has resulted in a clarification that is pertinent to our study. It is the intention to meet MARCA and WSCC reliability standards at all times. However, in the early stages of transmission construction, it may be desirable to utilize generation reserves at the load centers in lieu of transmission reserves. For instance, in the first part of the first stage if only one generator and one transmission line is built, local generation reserve would backup a line or generator outage.

The Transmission Committee will also consider similar alternates during initial operation which will still meet required standards. However, it is hoped that staging can be accomplished so that enough facilities will be constructed initially so that such alternate reserve methods will not be necessary.

Sincerely yours,

William F. Graham

William F. Graham
Study Manager

cc:
Mr. Don Hodel, Deputy Administrator, Bonneville Power Administration, 1001 N.E. Lloyd Boulevard, Portland, Oregon 97208
Mr. Peter C. King, Administrator, Southwestern Power Administration, P. O. Drawer 1619, Tulsa, Oklahoma 74101
Mr. K. Kristjanson, Director of Economics, Manitoba Hydro Commission, P. O. Box 815, Winnipeg, Manitoba

600

33.

To: Committee and Task Force Chairmen
North Central Power Study

Gentlemen:

There have been three Steering Committee and one Coordinating Committee meetings since the last (third) progress report, and although I believe you have all been informed of the latest instructions concerning the study, listed below are the main points which you should be aware of. Copies of this letter will be sent to the Steering Committee and if there are any further instructions, you will be informed.

1. Hydro-peaking

The length of time peaking would be available from pumped storage was questioned, therefore, pumped storage peaking will be considered two ways in the study: (a) As originally submitted, and (b) only those sites that are under $200 and which can sustain a minimum of 8 hours of capacity.

2. Legal Committee

The Legal Committee will do no further work on Phase One of the study with the following two exceptions: (a) Consider and reply to specific questions, and (b) write a short section for the report to the effect that no major obstacles can be foreseen to the implementation of the development.

3. Pacific Northwest Loads

Delivery of power to the Pacific Northwest will not be considered in this study. The new transmission system to the west to deliver NCPS power to Idaho, Utah, Colorado, Wyoming and Montana will be sized for adequate capacity and voltages as low as 230 kv will be used.

4. Load Magnitude to Study

The maximum delivery of power from NCPS generation will be one-third of the load growth in the study area (separate East and

West) between the years 1978 and 2000. From this maximum, various increments down to a practical minimum will be analyzed.

5. NCPS Load Location

The Transmission Committee will be responsible for determining the location and number of EHV and UHV substations where NCPS power will be delivered. After the sites are selected, the Steering Committee will approve the selection. (Individual utilities represented on the Coordinating Committee may make suggestions to the Transmission Committee concerning sites if desired.)

6. Stability Studies

It is not expected at this time that stability studies will be run on the computer but rather the Transmission Committee will design a stable system based on rules of thumb such as angles, cross-ties, etc. At a later date, the Transmission Committee may recommend actual stability studies if deemed desirable.

7. System Representation

The transmission computer power flow studies will show the underlying system as it is expected to be for 1980 in order to determine the effect of overlaying the NCPS transmission. It is not necessary to use the underlying system for all the "broad-brush" type of studies but it must be used to start in order to obtain realistic system behavior and get a feel for distribution of power flow.

8. System Reserves

The Steering Committee has now decided that both NCPS generation and transmission reserves will be carried on generation at the load centers. The Transmission Committee must consider this new policy directive and decide how much load center reserve is realistic (outage of one, two or ? lines or generations) and cost the reserves required. In any event the transmission system must be stable and still meet MARCA as well as WSCC reliability standards.

9. Existing Technology

It was agreed by the Coordinating Committee that the study must be conducted using existing technology. Such items as direct current circuit breakers, MHD, etc., may be commented upon but not included in the plan.

10. Transmission Cost Allocation

Costs of the transmission system will be allocated by three methods as follows:

A. Average rate (new name for postage stamp)
B. Kw-mile
C. Zone

Details of each method are attached.

11. Delivered Cost of Power

The study will consider both $/kw and mills/kwh cost of delivered power. Both the summary and technical reports will show enough detail so that the mills/kwh can be recalculated using different factors. Also the reports will state that the mills/kwh cost is to be used only as a very rough approximation until better information on actual financing can be obtained.

12. Costing Guidelines

The Economics Committee will advise all working groups concerned of revised factors to use in calculating annual costs (which include interest rates, taxes, etc.). It is imperative that when the other committees complete their costing work, the results be sent to the Economics Committee for review and consolidation as soon as possible.

13. Hydro-Thermal Blending

The report will show two basic types of power with associated costs:

A. Thermal power only.
B. Thermal-hydro (peaking) blend.

The Resources Committee will choose a practical blend of thermal and hydropower for inclusion in the study.

14. Transmission Environmental Considerations

The Transmission Committee will have the responsibility of the environmental aspects of transmission design and locations. If necessary they may consult with the Environmental Committee.

If you have any questions, please feel free to either call or write for clarification.

I also want to add that as of now the study is progressing on schedule and the work of your committees and task forces has been excellent. If you can just keep this pace up, we will have a good study completed on time.

Sincerely yours,

William F. Graham
Study Manager

Enclosures 2

cc:
Mr. Stanley M. Swanson, Chairman, Steering Committee, North Central Power Study, Iowa Public Service Company, Orpheum Electric Building, P. O. Box 778, Sioux City, Iowa 51102
Mr. D. L. Bryner, Manager, Planning, Utah Power and Light Company, 1407 W. N. Temple Street, P. O. Box 899, Salt Lake City, Utah 84110
Mr. John J. Bugas, Manager, Colorado-Ute Electric Association, Inc., P. O. Box 1149, Montrose, Colorado 81401
Mr. E. C. Glass, Director of Planning, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401
Mr. James L. Grahl, Manager, Basin Electric Power Cooperative, Provident Life Building, 316 Fifth Street North, Bismarck, North Dakota 58501
Mr. Ralph W. Shaw, Assistant General Manager, Omaha Public Power District, 1623 Harney Street, Omaha, Nebraska 68102
Mr. Arie M. Verrips, City Manager, Sioux Center, Iowa 51250

bc:
Commissioner (In duplicate), Attn: 600
600, 610

Transmission Cost Allocation Methods

1. "Average" transmission cost -

   For this method, each participating entity will share equally the transmission costs.

2. "Kw-mile" method -

   Use the following formula:

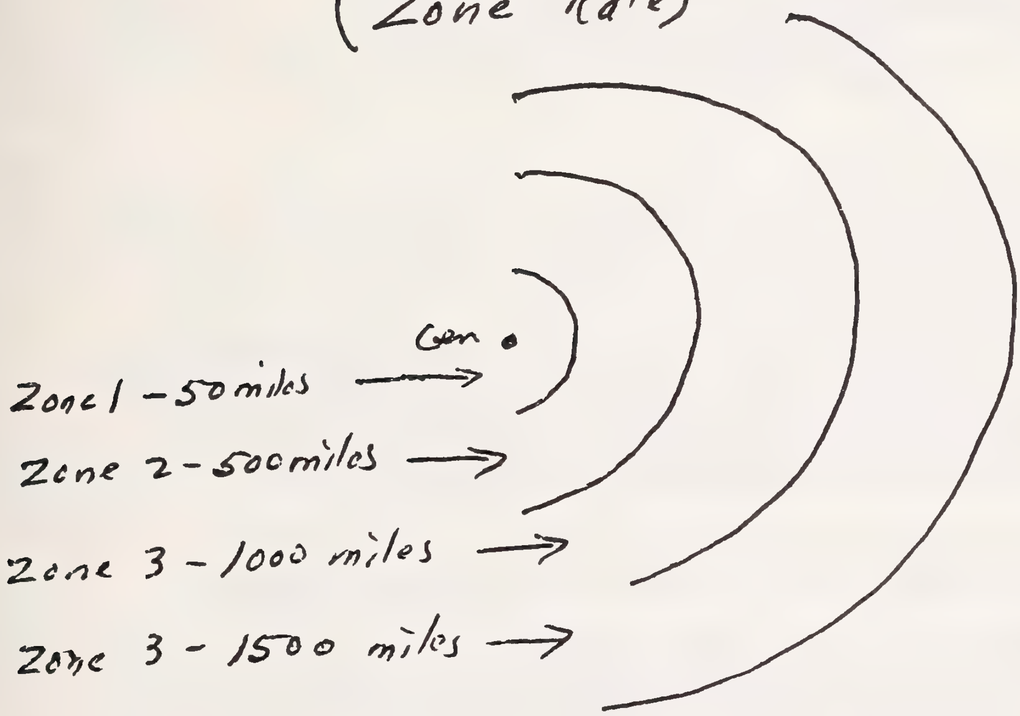
$$\text{Company A} = \tfrac{1}{4}\ \text{Invest.Total}\ \frac{(\text{MWA})}{(\text{MWT})} + 3/4\ \text{Invest.Total}\ \frac{(\text{MW-miles A})}{(\text{MW-miles Total})}$$

3. "Zone" rate -
   (See attached chart)

Note: Each of these three methods will be used separately for the East and the West.

Method III
("Zone" Rate)

See Revision
2-9-71



$$\text{Cost}_{Co.A} = \frac{1}{4}\,\text{Invest}_{TOT}\left(\frac{mw_A}{mw_T}\right) + \frac{3}{4}\,\text{Invest}_{TOT}\left(\frac{mw - \text{Zone}_A}{mw - \text{Zone total}}\right)$$

Example: $\text{Invest}_T = 100{,}000{,}000$ Load = 12,000 mw

					$\frac{mw-Z}{mw-Z_T}$
Z4	5000 mw	x 4	=	20,000	.526
Z3	5000	x 3	=	15,000	.395
Z2	1000	x 2	=	2,000	.053
Z4	1000	x 1	=	1,000	.026
	12,000 mw			38,000 mw-Z_T	1.000

So Co_A in Zone 3 with 2000 mw load costs:

$$Co_A = \frac{1}{4}(100{,}000{,}000)\left(\frac{2000}{12{,}000}\right) + \frac{3}{4}(100{,}000{,}000)(.395)$$
$$= \$\,33{,}766{,}667$$

North Central Power Study
Transmission Studies Outline
February 19, 1971
Revised March 4, 1971

In order to put into its proper perspective the work required by the Transmission Committee relating to transmission studies and (a) to define the work to be conducted, (b) to describe the method of doing the work, and (c) to have a realistic time schedule, the following draft of outline is presented. Upon approval of the Steering Committee, it will be followed. The outline incorporates the latest directives of the Steering Committee and presents a plan that is feasible of accomplishment within the allotted time with manpower available.

The Transmission Committee has four basic duties to accomplish concerning transmission studies for the North Central Power Study:

1. Develop EHV transmission plans with possible alternates. To the East this includes plans for generation of 3,000, 10,000, 20,000, 40,000, and 43,000 (includes 3,000 mw of hydropeaking) megawatts. To the West this includes 3,000, 5,000, and 10,000 megawatts. Transmission load factors for thermal generation only should approach 100 percent, depending on the number of generating units and scheduled maintenance requirements.

2. Develop both investment and annual costs for these transmission plans.

3. Estimate the reserves necessary for the plans and have the Generation Task Force assign costs as necessary.

4. Write the study report(s) required.

5. The time schedule for this work was established by the Study Manager's flow chart dated September 2, 1970, and shows detailed work accomplished by June 1 and the report drafts completed by July 1, 1971.

Basic theory to be used in running the studies is given below:

1. Computer Studies

EHV system only studies will be run to test East System plans for generation levels of 3,000, 10,000, 20,000, 40,000, and 43,000 mw.

Only the 3,000-mw development of generation for the East will be checked on the computer upon a projected 1980 base transmission system. A case will be run on the preliminary 1980 system and various plans may be later tested on a refined 1980 system. The purpose of these cases will be twofold: (a) To determine effect of the EHV on the underlying system; and (b) to determine the effect of the underlying system on phase angles of the EHV system.

West system studies will not be run on the computer but practical transmission systems will be developed from the coalfields to a point near Medicine Bow, Wyoming, for thermal generation of 3,000, 5,000, and 10,000 mw.

2. Loading Conditions

Due to the tight time schedule and shortage of manpower, only the 1980 summer heavy loading for the underlying system will be studied. For the preliminary information to be developed, it is considered adequate to only study the one season.

3. Probability Studies

It is not now planned to run probability studies on the computer due to shortage of both time and manpower. Sizing of units will be made by the Generation Task Force from knowledge on probability outages and outage data for unit sizes of 500, 750, and 1,000 mw. The decision will be based on reserves required for scheduled maintenance outages of units, size of the generation development, transmission, stability, and other such factors. The Task Force must determine when a spare unit is needed in the coalfields (for instance, 12 units each requiring 4 weeks annual maintenance should require one spare unit). The Task Force should present its recommendations at the next Steering Committee meeting.

4. Reserves

Generation reserves for this study will be considered to equal the reserve requirement of alternate local generation and therefore will not be costed. A check will be made to be sure that local generation reserves for transmission line outages will be less than that required for generation reserve requirements as it is anticipated. If the generation reserves required for transmission outages are higher, then they must be costed.

5. Manpower

Manpower requirements to complete the transmission study according to the attached schedule are available. It is understood that the Task Force and Committees serve only in an advisory and leadership capacity and the actual detail work will be done by Reclamation personnel.

6. EHV Delivery Points

The following NCPS delivery points that the Transmission Committee had recommended for Steering Committee approval were reviewed:

a. Eastern area delivery points:

Fort Thompson	Des Moines	Kansas City
Sioux Falls	Eastern Nebraska	St. Louis
Twin Cities	Western Nebraska	

The Steering Committee requested that the above points in the East be reviewed and either (a) reduce number of points for the 3,000 generation, or (b) increase the 3,000-mw minimum to 5,000 mw. The amount of power in the first stage does not appear to warrant eight delivery points.

b. Medicine Bow, Wyoming, was the only Western area delivery point. Pacific Power and Light Company and The Montana Power Company will take delivery direct from generator buses.

As the studies progress it may be desirable to add a few more delivery points.

7. Generation Magnitude

One-third of the 1980-2000 load growth to the East and West, respectively, is 36,000 and 7,600 megawatts including municipals. Therefore, the maximum deliveries (rounded after adding 1978-1980 load growth) was chosen as 40,000 and 10,000. Minimum generation considered feasible for study for either East or West was 3,000 megawatts. For the maximum deliveries only 3,000 megawatts of hydropeaking for the East will be considered to determine incremental transmission additions required.

United States Department of the Interior

BUREAU OF RECLAMATION
Regional Office, Region 6
P. O. Box 2553
Billings, Montana 59103

IN REPLY REFER TO: 610

34.

To: All Committee and Task Force Chairmen
Steering Committee
North Central Power Study

Gentlemen:

In order to clarify the responsibilities and to delineate the method for supplying cost information for our study, the following procedure is given for your information and action as appropriate.

First a few points to clarify the latest developments of Phase I of the study at this time.

1. On the West, computer transmission studies will not be required and hydro pumped storage will be considered in the individual utilities' alternate costs of generation rather than in the NCPS.

2. From the information supplied by the Coal and Byproducts Task Force, it has been decided to use a generation source at Gillette, Wyoming, for both the East and the West. It should be noted that the Colstrip, Montana, site would be similar in cost but would be a little further to market. For purposes of costing of water supply, the sites to be considered are numbers 28 through 37 shown on page 13a of the NCPS Progress Report No. 3.

3. The pumped storage sites that have been chosen are (a) the Cutler Park of 1,760 mw and (b) the Sheep Mountain of 1,240 mw, both in Wyoming fairly near Gillette, Wyoming.

4. Size of development at generation site to be considered for Phase I of our study is given below:

a. East: 3,000, 10,000, 20,000, 40,000 mw of thermal generation and 3,000 mw of hydro pumping at the 40,000 mw level.

b. West: 3,000, 5,000, and 10,000 mw of thermal generation.

With the above facts in mind, the attached costing flow chart is given to guide you in your costing. Given below are some additional comments concerning the detailed requirements of each Committee or Task Force.

1. General:

a. There are eight developments (five East and three West) that must be costed. In addition the Transmission Committee may desire alternate transmission plans for certain developments.

b. Both $/kw and mills/kwh costs will be obtained. Costs will be based on 1970 levels. Costs for both 1970 and 1975 levels will be shown with the indexing figures used between 1970 and 1975 listed.

c. The attached costing plan shows the various steps involved and the numbers shown indicate a logical sequence for timing the flow of data although some steps may be simultaneous.

2. Economics Committee (Steps 1 and 9)

The Economics Committee must give the Resources and Transmission Committees the information on cost of money, taxes to be used, costs of money to apply to depreciation (or replacement) factors and life of project assumed, also 1970-75 escalation factors.

The last step (9), after receiving the generation and transmission costs for each development, is for the Economics Committee to obtain the total delivered cost of power combining transmission costs (for various developments, plans, and alternate methods of apportioning transmission costs) and generation costs (for various developments) and writing its report.

3. Environmental Committee (Step 2)

Any special environmental costs such as land reclamation and air pollution controls must be given to the Resources Committee as soon as possible in order for these costs to be factored into the overall plan. Environmental costs associated with transmission will be obtained by the Transmission Committee itself with assistance from the Environmental Committee as required.

4. Resources Committee

In the attached costing plan, the Resources Committee is shown as the overall guiding agency for its task forces. Inside the dashed line is shown one method of how each task force should function; however, the Resources Committee may make changes as appropriate in order to get the job done.

5. Coal and Byproducts Task Force (Step 3)

This Task Force must get the fuel costs to the Generation Committee as soon as possible. From prelininary information available, the Gillette site has been selected with fuel costs of between 11 and 13 cents per million BTU, but this must be confirmed.

6. Water Supply Task Force (Step 4)

With the information now available this Task Force can supply the cost of cooling water and these costs should be given to the Generation Task Force.

7. Generation Task Force (Steps 5 and 7)

From the information obtained above and from its own work, the Generation Task Force can now derive the cost of generation (both $/kw and mills/kwh) for each of the eight thermal generation developments, and can then do steps 5 and 7. After the Hydro Task Force completes its work (step 6) then the Generation Task Force can complete its work by supplying the Economics Committee its final costs as shown as step 7.

8. Hydro-Generation Task Force (Step 6)

After receiving cost of pumping energy from the Generation Task Force (step 5), this Task Force can now derive the total investment and annual cost for the 3,000 mw of pumped storage and give this information to the Generation Task Force.

9. Transmission Committee (Step 8)

Losses will not be costed but merely subtracted from the total supply. The Transmission Committee is then able to derive the costs for transmission for each of the developments and alternate transmission plans. (The Transmission Committee must also calculate the costs of transmission from the two pumped storage sites to Gillette as well as the overall costs to delivery points.) The Transmission Committee should calculate the transmission costs for various delivery amounts based on the three methods of (a) average costs, (b) mw-mile cost, and (c) mw-zone costs.

It is hoped the above plan will give us a coordinated approach to the overall costing required for the NCPS. It is realized that some other approaches could be made (such as having the Economics Committee do more detailed work); however, it is believed that this plan will be the most productive when considering (a) who has the basic information to work with, (b) individual capabilities of assigned personnel, and

(c) workload division. It should be remembered that the Economics Committee must review all cost data submitted and is to "second-guess" the other working groups and ask for more data on any costs that are questionable.

Please do not hesitate to contact me if you have questions on the costing plan.

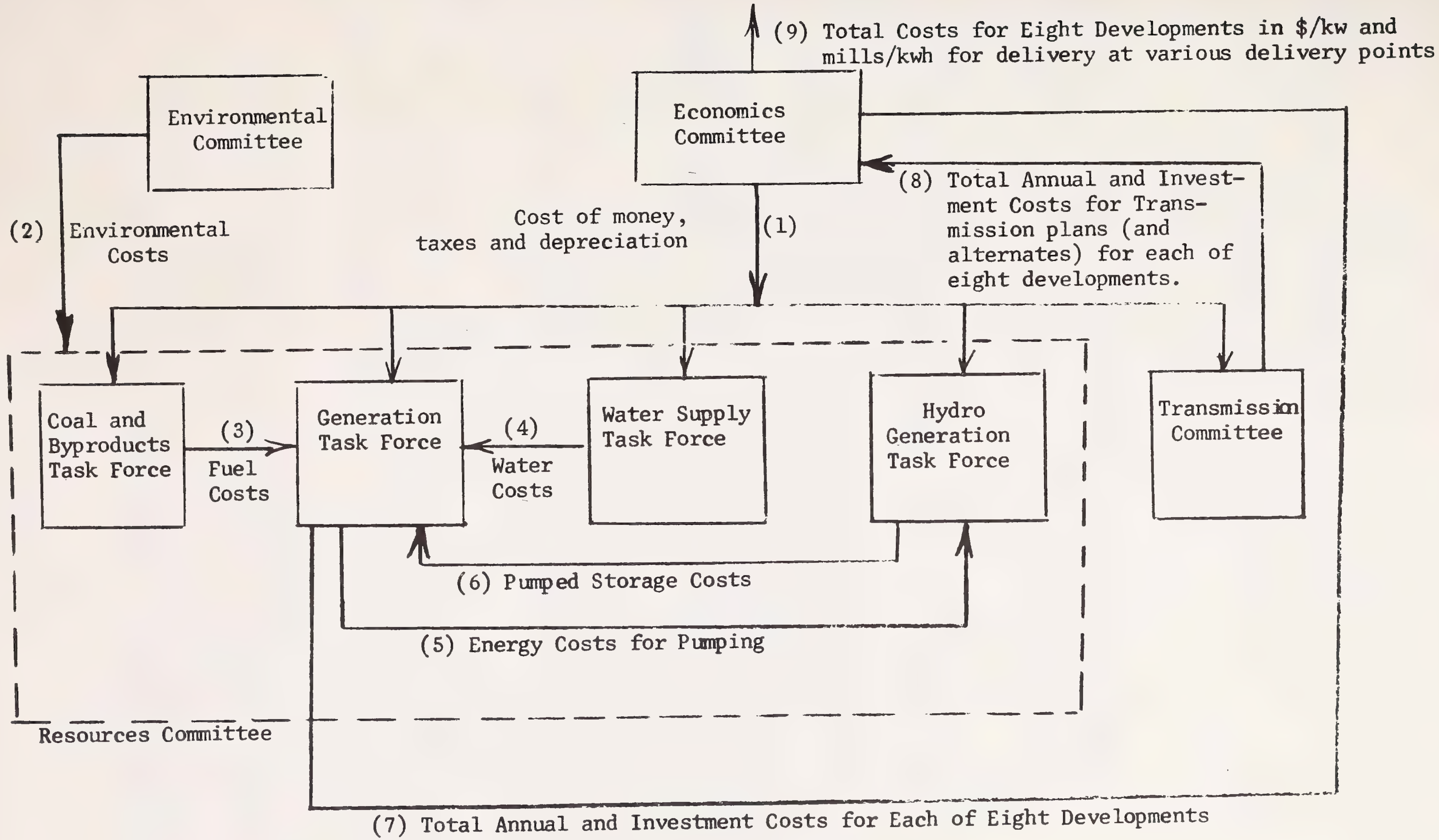
Sincerely yours,

William F Graham

William F. Graham
Study Manager

Enclosure

COSTING PLAN (North Central Power Study)



3-12-71

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39.

To: All Committee and Task Force Chairmen
Steering Committee
North Central Power Study

Gentlemen:

As a result of our March 29 and 30, 1971, Steering Committee meetings, we have some changes in our study direction which should be written for clarity. Given below are the items you should be aware of.

1. Transmission Studies. The Steering Committee wants to investigate the effect of shorter transmission (to Minnesota) from the lignite fields in North Dakota with higher generation and fuel costs vs. the generation site in the Gillette-Colstrip area. Therefore the Transmission Committee has been instructed to immediately put the highest priority on running computer studies for the 3000-mw generation complex serving eastern loads at both the Gillette, Wyoming, site and the Beulah, North Dakota, site. Only 500-kv transmission will be used for the immediate comparison of the two sites and studies will be overrun on the 1980 base system. At the completion of the computer studies, the Steering Committee will be consulted to see if: (a) Transmission of each must be costed, (b) generation must be costed, (c) additional studies will be made on the North Dakota site, or (d) studies will resume on the Gillette-Colstrip site.

2. The Steering Committee has revised the costing instructions given in my March 12, 1971, letter. For ease of understanding, a revised copy of the March 12 letter is enclosed. In effect, the Economics Committee will do the bulk of the costing consolidation and the other working groups will only supply investment and fixed O&M costs.

3. It must be reemphasized that all costs should be based on 1970 costs. Escalation factors furnished by the Economics Committee will be used to derive 1975 costs which will also be reported.

4. Individual committees and task forces will be required to submit two reports: (a) A short summary report, and (b) a detailed technical backup report. All drafts of these reports should be

submitted to the following people so that early review as well as pertinent feedback can be obtained:

1. Committee Chairman (if appropriate)
2. Study Manager
3. Steering Committee
4. Chairman - Economics Committee
5. Chairman - Report Committee

5. The Steering Committee has requested cooling water delivery costs for both with and without energy company participation. The Water Supply Task Force has been so instructed to obtain these costs. It is noted that there is no variation in water supply costs for a 3000-mw development vs. a 50,000-mw development and this should be explained in the report.

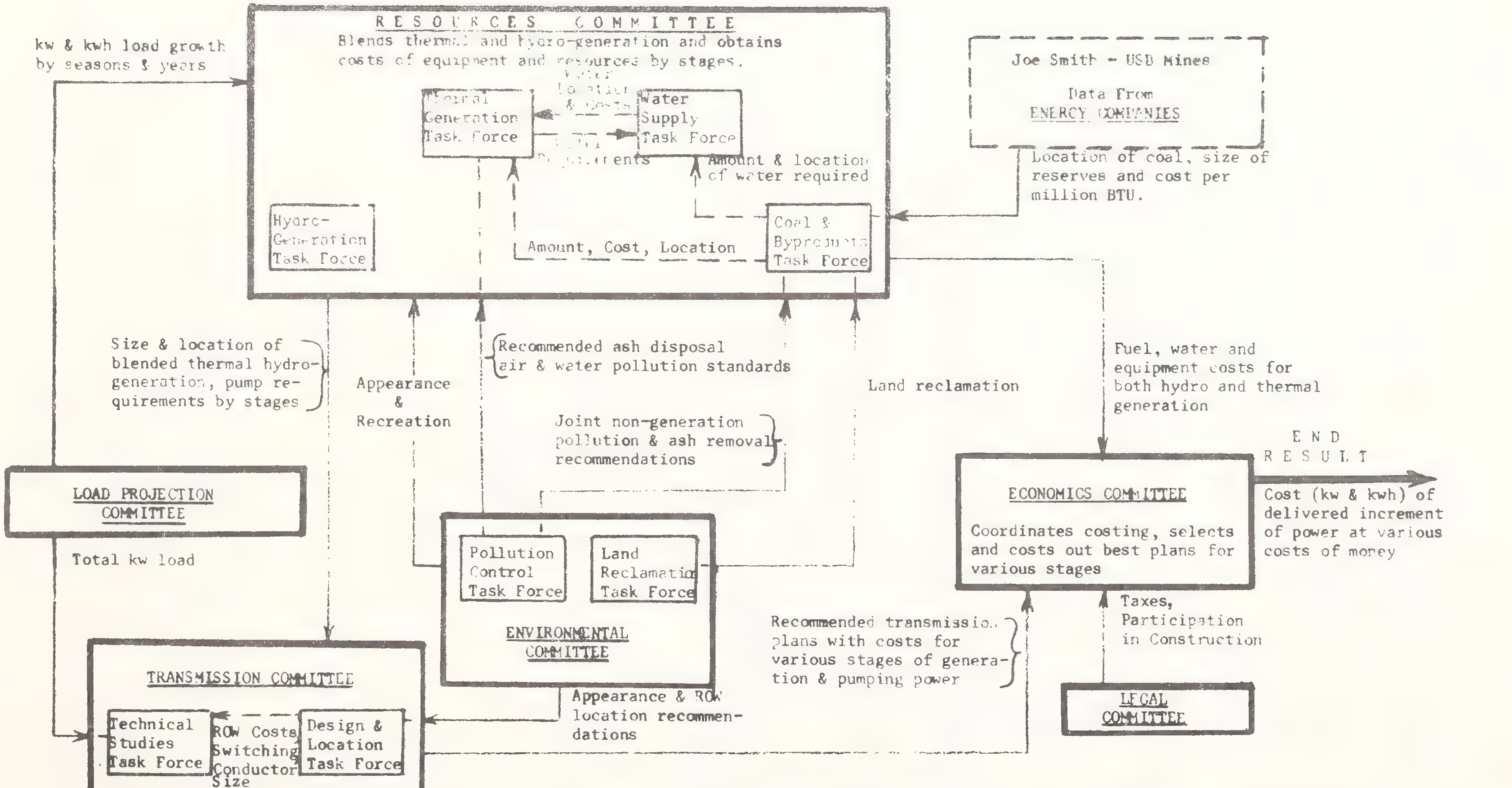
6. The method of obtaining costs of mills/kwh received detailed attention again by the Steering Committee. Although the method to be used was not resolved, the Economics Committee has been asked to study the problem and was directed to specifically look into a series of graphs which could convert size of development, distance, fixed charge rate, mw load and individual investment into mills/kwh.

The many changes directed by the Steering committee will cause delay for some individual committees in completing their work. However, it is hoped that we will not fall very far behind our originally published time schedule.

Sincerely yours,

William F. Graham
Study Manager

Enclosure

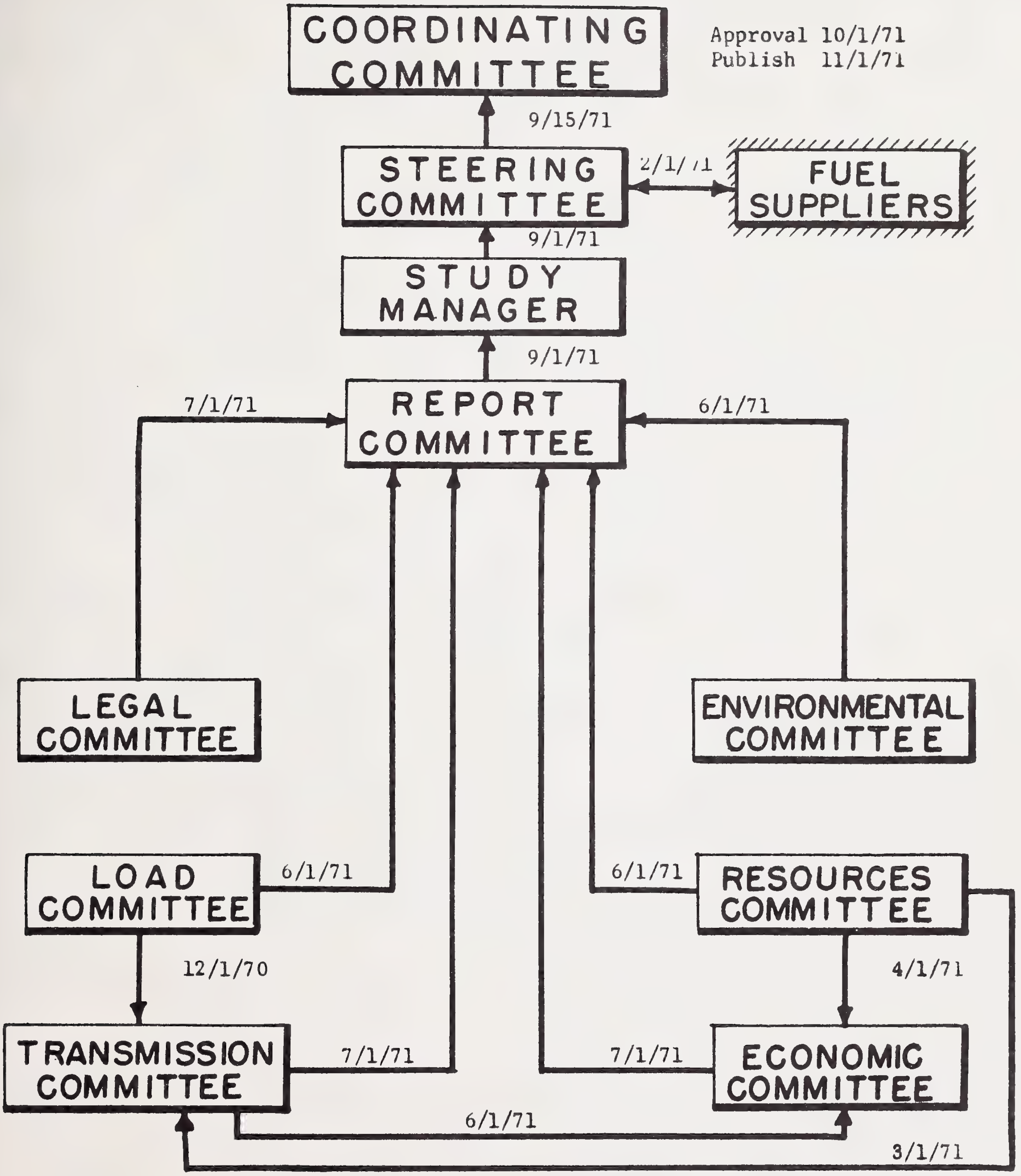


FLOW CHART (Preliminary)
NORTH CENTRAL POWER STUDY

Date 10-5-70, Rev. 10-29-7?

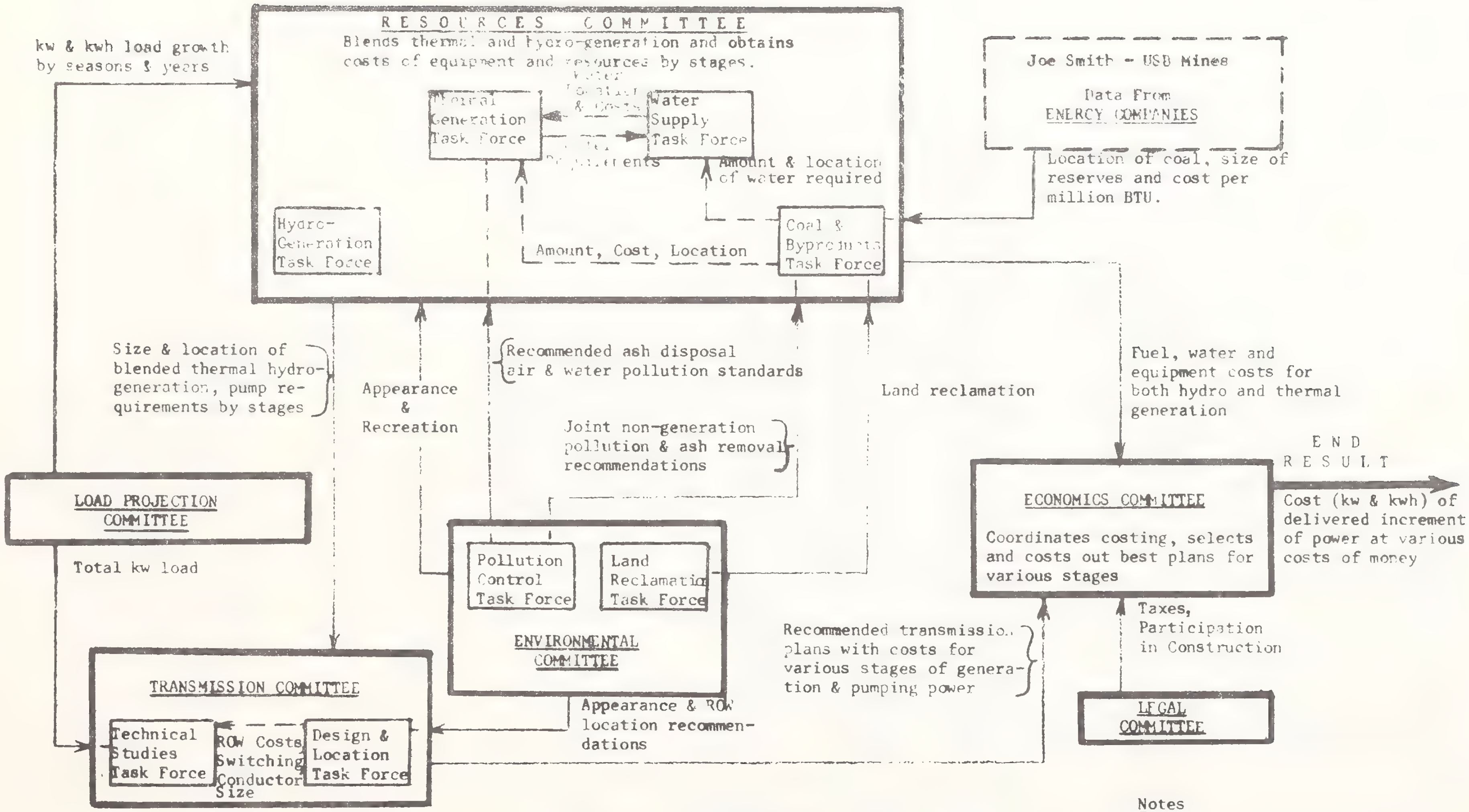
Notes

1. All outputs are also sent to Study Manager.
2. Consultations between Committees and Task Forces must be established as required.



DATA AND REPORT TIME TABLE

Dates are latest submission (hopefully earlier—should at least be partial submission before).



FLOW CHART (Preliminary)
NORTH CENTRAL POWER STUDY

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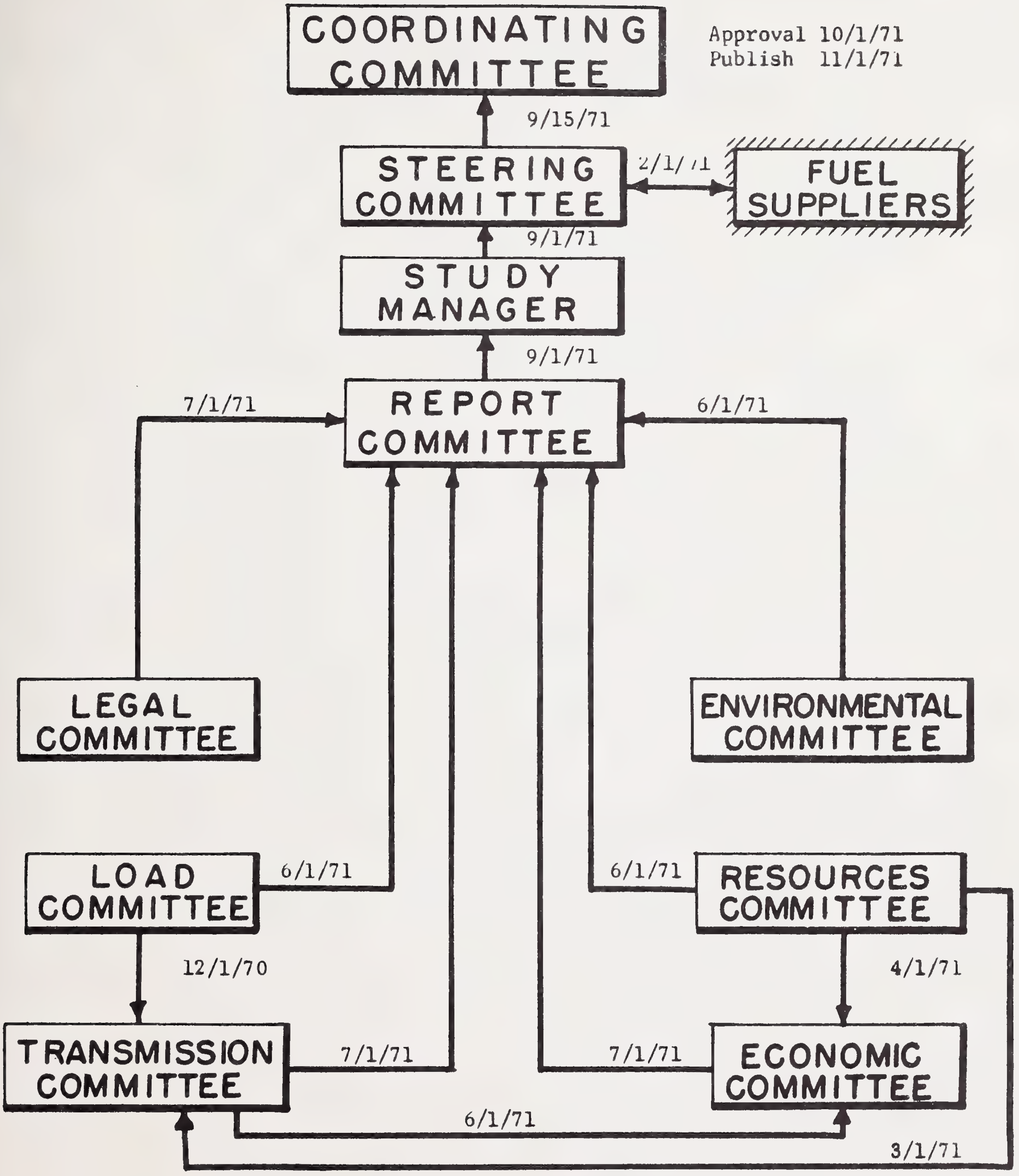

DATA AND REPORT TIME TABLE

Dates are latest submission (hopefully earlier—should at least be partial submission before).

NORTH CENTRAL POWER STUDY

III. Report of Legal Committee

Conclusion

The Committee knows of no overriding obstacles to development of large generating complexes and a transmission system in the North Central region.

History

The Legal Committee met at the Airport Inn in Omaha, Nebraska, on November 15, 1970. Messrs. William Wisdon, A. D. Brusven, Leonard B. Desmul (in place of A. E. Bielefeld), and R. D. Wilson were present. Mr. Ernest London was unable to attend.

On December 7, 1970 an Interim Report of the Legal Committee was submitted. Thereafter, through the Study Manager, the Steering Committee and Coordinating Committee issued instructions that the Legal Committee do no further work on Phase One of the study with the following two exceptions: (a) Consider and reply to specific questions, and (b) write a short section for the report to the effect that no major obstacles can be foreseen to implementation of the development.

No specific questions were submitted.

Rationale

Until a particular development is actually proposed, no specific legal research or memoranda can be developed. In this connection, there is need for answers to a number of questions such as the following:

1. The size of the proposed generating facilities should be determined. If the plant is so large that a large number of participants will be necessary, that will require consideration of different schemes of participation than if the plant is much smaller and only a few organizations participate.

2. The number and type of participants must be known before contract can be worked out.

3. The location of the proposed plant will determine which local laws are involved.

4. The exact location of the proposed plant needs to be known before contracts can be developed to be used with the owners of resources involved.

5. The number and type of participants will determine what financing plans to be used.

6. Until it is known what transmission lines will be built, the areas they will transverse and the purposes they will serve, it is not really feasible to work out legal arrangements as to construction, operation and interconnection.

In spite of the inability to develop specific contract forms until the answers to the above questions are known, the Committee can report that it knows no overriding legal obstacles to development of large generating complexes and a transmission system in the North Central region.

IV. LOAD PROJECTION

Volume II
North Central Power Study
Electric Power Loads
Load Projection Committee

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4. Typical Area Weekly Load Energy Distribution - 1st Full Week in August
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Samples of Sheet II, Area Load-Generation Summary Submitted by members of Coordinating Committee

Volume II
North Central Power Study
Electric Power Loads
Load Projection Committee

Purpose

This report summarizes the activities of the Load Projection Committee of the North Central Power Study, which was given the responsibility of estimating the power load requirements for the North Central Power Study area for the years 1980, 1985, 1990, and 2000.

Scope

The North Central Power Study area includes the states of Idaho, Montana, Wyoming, North and South Dakota, Nebraska, Minnesota, Iowa, and parts of Colorado, Utah, Kansas, Missouri and Wisconsin.

Study area loads are considered to be all loads within the North Central Power Study area boundaries whether served or not served by the Coordinating Committee members of the North Central Power Study.

For purposes of transmission computer studies, the total North Central Power Study area was divided into the East and West System areas to generally coincide with the East-West transmission ties, and only the East System transmission studies are to be made at this time.

Electric power load estimates by summer (May - Oct.) and winter (Nov. - April) seasons for the years 1980, 1985, 1990, and 2000 were obtained from each North Central Power Study Coordinating Committee member. Also, estimates of municipals, and other power systems not included in the Coordinating Committee estimates were obtained to provide complete coverage of power loads in the study area.

Study Procedure

Instead of using load estimates from existing reports, each member of the Coordinating Committee was requested (letter of Sept. 28, 1970) to prepare estimates of their system seasonal demand and energy requirements by load points for the years 1980, 1985, 1990, and 2000; indicating for their system such items as transmission losses, reserve generating capacity obligation, net generating capacity owned or planned, planned interchange with other power systems, and amounts of power which they would consider purchasing from the proposed North Central Power source. Information requested in addition to system load requirements was deemed necessary and beneficial for other Committees of the North Central Power Study.

No attempt was made to estimate the electric power requirements for the mining and processing of fuel and the pumping of water required for the proposed North Central Power production facilities; the assumption was made that this would be covered by the committee responsible for sizing of the powerplants.

Results

The load data as obtained from the reporting entities were assembled and compared with Federal Power Commission Power Supply Areas load estimates to determine if the study load estimates were within estimating error range. It was found that for power supply areas wholly within the boundaries of the study area, the North Central Power Study load estimates for 1980 compared very favorably with the Federal Power Commission estimates for the same year. Therefore, it is assumed that the load estimates prepared for the North Central Power Study are within the range of accuracy required for this type of study.

Chart 1 and Tables 1 and 1a indicate the total North Central Power Study area estimated seasonal peakload requirement for years 1980 through 2000. The total North Central Power Study area noncoincidental summer peakload demand is estimated to be about 51,000 mw in 1980, and increases to about 181,000 mw in 2000, an increase of 130,000 mw over the 20-year period for an average annual growth rate of 6.5 percent. The study area noncoincidental winter peakload demand is estimated to be about 44,000 mw in the 1980-81 winter, and increases to about 154,000 mw in the 2000-01 winter, an increase of 110,000 mw over the 20-year period for an average annual growth rate of 6.4 percent. This indicates that the demand growth rate in the study area is below the average annual growth rate of 7.2 percent which would double a load each 10 years. North Central peak demand estimates indicate that the average annual growth rates would increase the loads about 1.77 times in 10 years during the summers, and about 1.75 times in 10 years during the winters.

The 1964 National Power Survey (Federal Power Commission) estimated the 1980 noncoincidental peak demand of the contiguous United States at about 494,000 mw. The North Central Power Study area noncoincidental summer peak requirement as estimated for 1980 (51,000 mw) is about 10 percent of the total requirements of the contiguous United States. Estimates indicate that the geographic North Central Power Study area is roughly 34 percent of the area of the contiguous United States; and by 1980, it is estimated that the North Central area population may be about 10 percent of the population of the contiguous United States.

The North Central Power Study area was divided into two systems. East and West, to generally coincide with the East-West transmission ties, and transmission studies of the East System only are being prepared at this time.

Chart 2 and Tables 2 and 2a indicate the East System area estimated seasonal peak demand and energy requirements for years 1980 through 2000. The East System noncoincidental summer peakload demand is estimated to be about 39,000 mw in 1980 and increases to about 147,000 mw in 2000, an increase of 108,000 mw over the 20-year period for an average annual growth rate of about 6.9 percent. The East System noncoincidental winter peakload demand is estimated to be about 33,000 mw in 1980 and increases to about 120,000 mw in 2000, an increase of 87,000 mw over the 20-year period for an average annual growth rate of about 6.7 percent. Load estimates for the East System indicate that the average annual growth rate will increase the peakload demands about 1.88 times in 10 years during the summers and about 1.82 times in 10 years during the winters.

Estimated summer energy requirements for the East System increase from about 92,000 gwh in 1980 to about 334,000 gwh in 2000, for an average annual energy growth rate of 6.7 percent. Winter energy requirements increase from about 90,000 gwh in 1980 to about 320,000 gwh in 2000, for an average annual energy growth rate of 6.6 percent. These North Central energy growth rates will increase energy requirements 1.82 and 1.78 times in 10 years in summer and winter respectively.

The West System noncoincidental summer peakload demand is estimated to be about 12,000 mw in 1980 and increases to about 34,000 mw in 2000, an increase of 22,000 mw over the 20-year period. System noncoincidental winter peakload demand is estimated to be about 11,000 mw in 1980 and increases to 34,000 mw in 2000. See Chart 1 for the West System load projection. Data for analysis of energy requirements and load factors for the West System was not available at the time of this report.

The load to be served from the NCPS development was restricted by study criteria to one-third of the load growth in order to obtain a suitable balance between local generation at the load centers and the remote generation in the coalfields. For the Eastern System one-third the total load growth between 1978 and 2000 is approximately 40,000 mw and for the Western System about 10,000 mw. Studies were run at 3,000, 10,000, 20,000, and 40,000-mw levels for the East and 1,000, 3,000, and 10,000 for the West.

Table 3 gives a comparison of North Central Power Study load estimates by FPC Power Supply Areas with Federal Power Commission load data for the year 1980. Table 3 also includes a tabulation of loads by classes of service, indicating that of the East System loads, 70 percent is served by private power companies, 20 percent is served by cooperatives, and 10 percent is served by municipals and others.

The following charts were developed from data contained in 1968 Federal Power Commission reports for the East System North Central Power Study Coordinating Committee members. These charts present certain area load characteristics, and are assumed to be representative of the North Central East System composite area loads. Load characteristic for any specific area or power system may be quite different--these charts are included to indicate the composite East System load characteristics. Further study, using current data as compared to the 1968 FPC data would reveal changes due to different types and concentrations of loads within the East System.

Charts 3 and 3a - Typical hourly load curves for the first full week in August and December. On-peak loads have considerable duration because of the large area and time zone coverage. In comparison, any one power system within the East System would have much sharper peaks and shorter duration of on-peak demand.

Chart 4 and 4a - Typical daily load energy requirement distribution for the composite East System for the first full week in August and December.

Chart 5 - Typical monthly energy requirement for the composite East System.

Chart 6 - Typical monthly load demand pattern based on percent of annual peak demand.

Chart 7 - Typical monthly and annual load factors.

Included are two samples of the Area Load-Generation Summary data, Sheet II, received from members of the Coordinating Committee. Copies of each of the Coordinating Committee Area Load-Generation Summary data (Sheet I showing loads and generation by load points, and Sheet II showing loads and generation by system) are not included in this report in an attempt to keep the volume of material within reasonable limits.

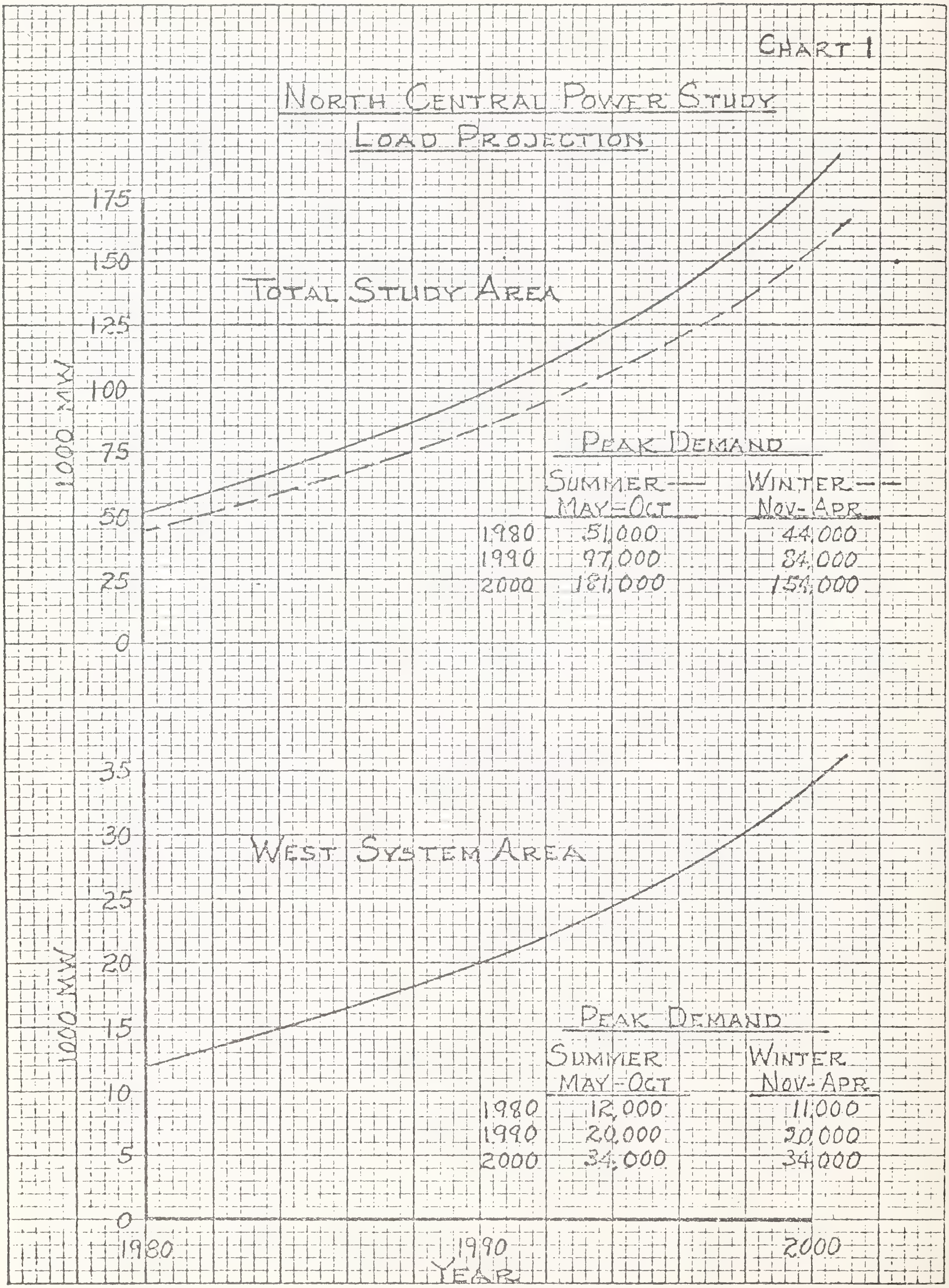


CHART 1
NORTH CENTRAL POWER STUDY
LOAD PROJECTION
TOTAL STUDY AREA
1000 MW
175
150
125
100
75
50
25
0
PEAK DEMAND
SUMMER
MAY-OCT
WINTER
NOV-APR
1980 51,000 44,000
1990 97,000 84,000
2000 181,000 154,000
WEST SYSTEM AREA
1000 MW
35
30
25
20
15
10
5
0
PEAK DEMAND
SUMMER
MAY-OCT
WINTER
NOV-APR
1980 12,000 11,000
1990 20,000 20,000
2000 34,000 34,000
1980
1990
2000
YEAR

Table 1

NORTH CENTRAL POWER STUDY AREA LOADS

MW and Avg. Annual Growth
(Summer Peak Demand)

1/	1980	%	1985	%	1990	%	2000	1980-2000 % Growth
Assoc. E Coop.	1,856	10.0	2,986	10.0	4,814	10.0	12,486	10.0
BEP Coop. (West)	794	5.5	1,038	5.5	1,356	5.1	2,226	5.3
BEP Coop. (East)	1,171	5.3	1,517	5.3	1,965	5.4	3,321	5.3
BHPL	168	5.1	215	5.7	284	5.2	473	5.3
DPC	479	7.0	671	6.9	933	6.9	1,811	6.9
IIGE	1,257	7.2	1,780	7.2	2,519	6.4	4,700	6.8
IPL	1,319	6.0	1,766	6.0	2,363	6.0	4,231	6.0
ISP	808	6.0	1,080	5.0	1,378	5.0	2,245	5.2
IELP-CIPCO	1,318	8.0	1,940	8.0	2,853	7.9	6,111	8.0
IPS	876	6.9	1,222	8.0	1,800	7.5	3,700	7.5
ISU	527	8.0	774	7.0	1,086	7.0	2,130	7.2
KCPL	2,816	6.5	3,858	6.5	5,285	6.5	9,922	6.5
MDU	270	4.3	334	4.4	415	4.7	654	4.5
MPL	1,152	5.0	1,467	5.1	1,878	2.9	2,506	4.0
Municipals 2/	2,206	5.5	2,885	5.0	3,684	5.0	6,000	5.1
NWPS	272	5.9	362	5.9	481	5.9	855	5.9
NPPD	2,186	5.9	2,915	5.3	3,765	5.0	6,132	5.3
NSP	6,920	7.0	9,705	7.0	13,613	6.6	25,842	6.8
OPPD	1,669	4.5	2,082	3.9	2,528	3.3	3,503	3.8
OTP	332	6.0	444	6.0	594	6.0	1,065	6.0
UE 3/	9,129	7.4	13,046	7.4	18,644	7.4	38,077	7.4
UPA RCPA	348	11.9	610	7.1	860	5.9	1,530	7.7
NMPA	128	7.1	180	6.1	242	5.0	394	5.8
Region 6	2,435	6.2	3,295	6.3	4,476	6.9	8,704	6.6
Region 7 (East)	135	6.0	181	5.9	241	3.7	348	4.8
Region 7 (West)	395	10.8	659	9.7	1,046	10.1	2,748	10.2
Colo-Ute (West)	273	9.0	420	9.5	662	9.1	1,585	9.2
IPC (West)	782	3.4	924	3.9	1,119	4.6	1,747	4.1
MPC (West)	1,083	5.1	1,388	5.1	1,784	5.2	2,967	5.2
PSC Colo (West)	3,244	7.6	4,690	7.8	6,813	4.9	10,976	6.3
PPL (Wyo.) (West)	670	7.0	940	5.7	1,240	5.1	2,040	5.7
UPL (West)	2,780	5.2	3,590	5.5	4,690	5.6	8,110	5.5
Region 4 (West)	1,159	1.0	1,221	1.3	1,304	1.8	1,562	1.5
GRAND TOTAL	50,957	6.6	70,186	6.6	96,715	6.4	180,701	6.5
Total East System	39,777	6.8	55,316	6.8	76,701	6.7	146,740	6.7
Total West System	11,180	5.9	14,870	6.1	20,014	5.4	33,961	5.7

Total East System:
Load Growth 1980-2000 106,963 MW
One-Third 1980-2000 Load Growth 35,654 MW, Rounded to 40,000 MW for 1978-2000.

Total West System:
Load Growth 1980-2000 22,781 MW
One-Third 1980-2000 Load Growth 7,594 MW, Rounded to 10,000 MW for 1978-2000.

1/ See page IV-22 for full names of entities.

2/ Municipal loads for most of the area are included in Utility and Federal loads. Municipal loads in the extreme east and southeast part of the Study area are shown on this line.

3/ Later information indicates annual load growth of 6.25%.

NORTH CENTRAL POWER STUDY AREA LOADS

MW and Avg. Annual Growth
(Winter Peak Demand)

	1980-81	%	1985-86	%	1990-91	%	2000-01	1980-2000 % Growth
Assoc. E	1,893	10.0	3,046	10.0	4,910	10.0	12,736	10.0
BEP Coop. (West)	728	5.8	967	5.8	1,280	5.1	2,102	5.8
BEP Coop. (East)	1,447	5.8	1,919	5.8	2,543	5.8	4,465	5.8
BHPL	179	5.1	229	5.8	303	5.2	502	5.3
DPC	668	6.8	930	6.8	1,295	6.9	2,513	6.9
IIGE	1,016	7.0	1,424	7.2	2,015	6.4	3,760	6.8
IPL	966	6.0	1,292	6.0	1,730	6.0	3,097	6.0
ISP	715	6.0	956	5.0	1,220	5.0	1,987	5.2
IELP-CIPCO	1,160	6.9	1,619	6.9	2,261	6.9	4,411	6.9
IPS	697	5.8	924	7.6	1,330	6.5	2,500	6.6
ISU	387	7.0	543	7.9	796	8.0	1,720	7.7
KCPL	1,830	6.5	2,508	6.5	3,435	6.5	6,449	6.5
MDU	282	2.8	324	4.4	402	4.6	633	4.1
MPL	1,300	5.2	1,677	5.3	2,171	3.0	2,912	4.1
Municipals 1/	2,206	5.5	2,885	5.0	3,684	5.0	6,000	5.1
NWPS	190	6.0	254	5.9	339	6.0	605	6.0
NPPD	1,473	5.7	1,939	5.1	2,481	4.8	3,975	5.1
NSP	6,095	7.0	8,548	7.0	11,989	6.0	21,470	6.5
OPPD	1,053	4.8	1,334	4.4	1,653	4.0	2,452	4.3
OTP	435	6.0	582	6.0	778	6.0	1,393	6.0
UE 2/	5,906	7.4	8,441	7.4	12,063	7.4	24,636	7.4
UPA RCPA	371	10.3	605	7.2	855	5.9	1,520	7.3
NMPA	166	8.5	249	6.0	334	5.0	545	6.1
Region 6	2,591	6.5	3,543	6.6	4,874	6.7	9,340	6.6
Region 7 (East)	125	6.3	170	6.0	228	3.8	332	5.0
Region 7 (West)	435	9.9	698	9.0	1,075	9.2	2,588	9.3
Colo-Ute (West)	328	9.0	504	9.4	788	9.2	1,900	9.2
IPC (West)	630	2.7	718	3.2	839	3.9	1,225	3.4
MPC (West)	1,313	5.2	1,694	5.3	2,192	5.3	3,688	5.3
PCS Colo (West)	3,396	7.1	4,794	7.2	6,798	4.9	10,949	6.0
PPL (Wyo.) (West)	780	7.1	1,100	5.5	1,440	5.0	2,340	5.6
UPL (West)	2,540	5.2	3,290	5.4	4,270	5.6	7,360	5.5
Region 4 (West)	1,024	2.4	1,100	1.8	1,202	2.4	1,523	2.0
GRAND TOTAL	44,325	6.5	60,806	6.6	83,573	6.3	153,628	6.4
Total East System	33,151	6.7	45,931	6.8	63,689	6.5	119,953	6.6
Total West System	11,174	5.9	14,875	6.0	19,884	5.4	33,675	5.7

1/ Municipal loads for most of the area are included in Utility and Federal loads. Municipal loads in the extreme east and southeast part of the Study area are shown on this line.

2/ Later information indicates annual load growth of 9.6%.

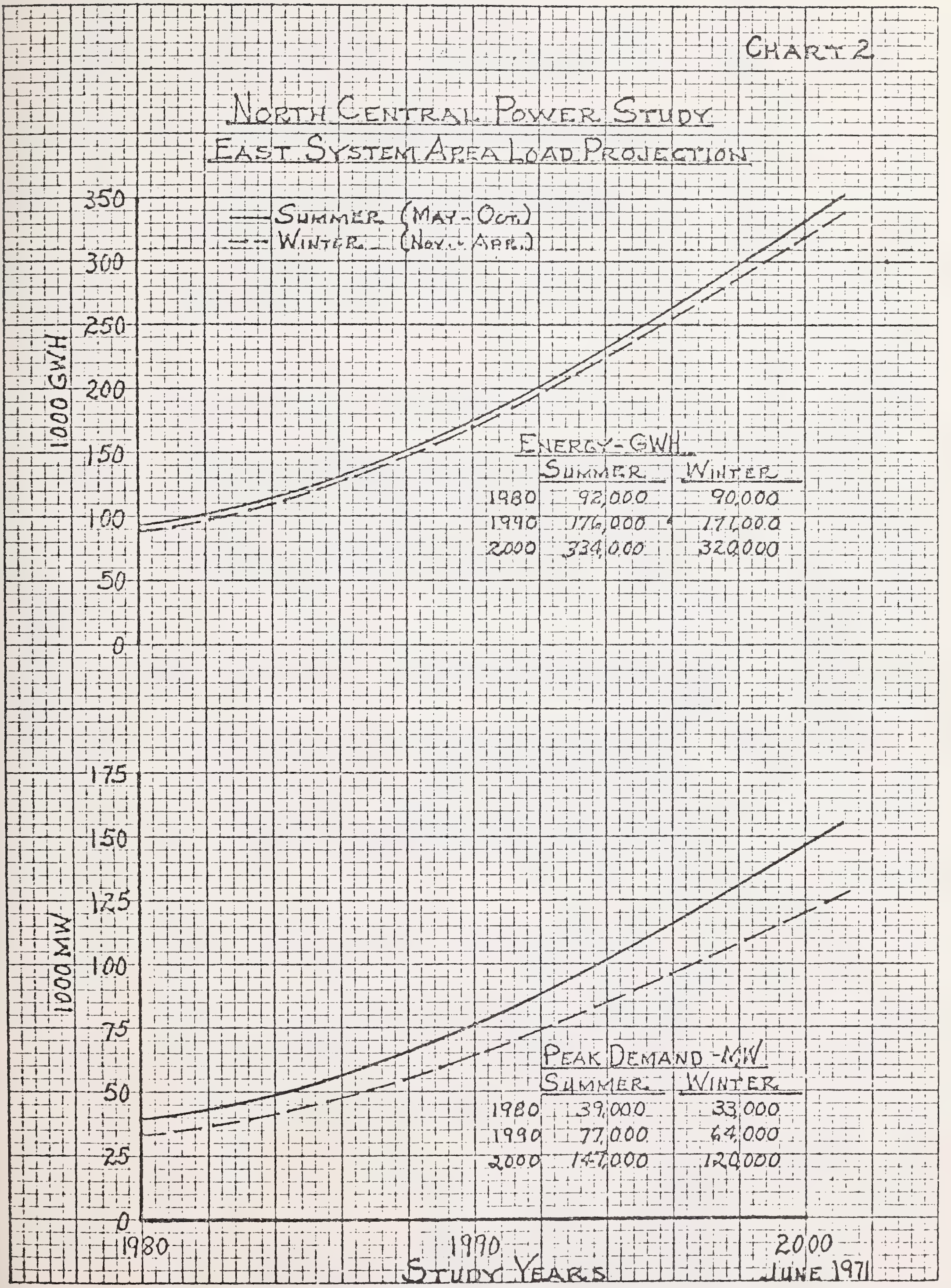


CHART 2
NORTH CENTRAL POWER STUDY
EAST SYSTEM AREA LOAD PROJECTION
SUMMER (MAY-OCT.)
WINTER (NOV.-APR.)
1000 GWH
350
300
250
200
150
100
50
0
ENERGY-GWH
SUMMER WINTER
1980 92,000 90,000
1990 176,000 171,000
2000 334,000 320,000
1000 MW
175
150
125
100
75
50
25
0
PEAK DEMAND-MW
SUMMER WINTER
1980 39,000 33,000
1990 77,000 64,000
2000 147,000 120,000
1980
1990
2000
STUDY YEARS
JUNE 1971

North Central Power Study
East System
Estimated Input Requirements
(W/O Reserve)

SUMMER (May - Oct.)	1980 MW	1980 GWH	1980 Season L.F.	1985 MW	1985 GWH	1985 Season L.F.	1990 MW	1990 GWH	1990 Season L.F.	2000 MW	2000 GWH	2000 Season L.F.	1980-2000 % Avg. Annual Growth MW	1980-2000 % Avg. Annual Growth GWH
Assoc. Elect.	1,856	4,098 2/	50	2,986	6,593 2/	50	4,814	10,629 2/	50	12,486	27,569 2/	50	10.0	10.0
Basin	1,171	3,361	65	1,517	4,354	65	1,965	5,640	65	3,321	9,533	65	5.3	5.4
BHP&L	168	355 2/	48	215	457 2/	48	284	596 2/	48	473	994 2/	48	5.3	5.3
DPC	479	1,250	59	671	1,790	60	933	2,600	63	1,811	5,550	69	6.9	7.7
IIGE	1,257	2,915	53	1,780	4,125	53	2,519	5,840	53	4,700	10,900	53	6.8	6.8
IPL	1,319	3,029	52	1,766	4,055	52	2,363	5,426	52	4,231	9,716	52	6.0	6.0
ISP	808	2,280	64	1,080	3,010	64	1,378	3,880	64	2,245	6,335	64	5.2	5.2
IELP-CIPCO	1,318	3,194	55	1,940	4,541	53	2,853	6,459	51	6,111	13,049	48	8.0	7.3
IPS	876	1,894 2/	49	1,222	2,645 2/	49	1,800	3,835 2/	49	3,700	8,006 2/	49	7.5	7.5
ISU	527	1,097	47	774	1,645	48	1,086	2,306	48	2,130	4,525	48	7.2	7.3
KCPL	2,816	6,394	51	3,858	8,760	51	5,285	12,000	51	9,922	22,529	51	6.5	6.5
MDU	270	790	66	334	967	66	415	1,202	66	654	1,894	66	4.5	4.5
MPL	1,152	4,123	81	1,467	5,196	86	1,878	6,587	79	2,506	8,764	79	4.0	3.9
Municipals 1/	2,206	4,871 2/	50	2,885	6,370 2/	50	3,684	8,134 2/	50	6,000	13,248 2/	50	5.1	5.1
NWPS	272	600	50	362	792	50	481	1,062	50	855	1,888	50	5.9	5.9
NPPD	2,186	4,557	47	2,915	6,238	49	3,765	8,254	50	6,132	14,070	52	5.3	5.8
NSP	6,920	15,129 2/	50	9,706	21,219 2/	50	13,613	29,764 2/	50	25,842	56,503 2/	50	6.8	6.8
OPPD	1,669	3,644	49	2,082	4,788	52	2,528	5,874	53	3,503	8,138	53	3.8	4.1
OTP	332	977	67	444	1,308	67	594	1,748	67	1,065	3,130	67	6.0	6.0
UE	9,129 2/	20,157 2/	50	13,046 2/	28,801 2/	50	18,644 2/	41,166 2/	50	38,077 2/	84,074 2/	50	7.4	7.4
UPA RCPA	348	762	50	610	1,336	50	860	1,883	50	1,530	3,351	50	7.7	7.7
NCPA	128	280	50	180	394	50	242	530	50	394	863	50	5.8	5.8
Reg. 6	2,435	5,271	49	3,295	7,206	50	4,476	9,865	50	8,704	18,963	50	6.6	6.6
Reg. 7	135	322	55	181	432	55	241	584	55	348	844	55	4.8	4.8
Total	39,777	91,357	52	55,316	127,066	52	76,701	175,924	52	146,740	334,436	52	6.7	6.7

1/ Minn., Iowa, Kansas, & Missouri (Other municipal loads assumed to be included in Coordinating Comm. Member loads).
2/ Not supplied by participant.

Table 2

Table 2a

North Central Power Study
East System
Estimated Input Requirements
(W/O Reserve)

WINTER (Nov. - April)	1980 MW	1980 GWH	1980 Season L.F.	1985 MW	1985 GWH	1985 Season L.F.	1990 MW	1990 GWH	1990 Season L.F.	2000 MW	2000 GWH	2000 Season L.F.	1980-2000 % Avg. Annual Growth MW	1980-2000 % Avg. Annual Growth GWH
Assoc. Elect.	1,893	4,934 2/	60	3,046	7,939 2/	60	4,910	12,979 2/	61	12,736	33,195 2/	60	10.0	10.0
Basin	1,447	3,960	63	1,919	5,252	63	2,543	6,960	63	4,465	12,220	63	5.8	5.8
BHP&L	179	448 2/	58	229	573 2/	58	303	753 2/	57	502	1,243 2/	57	5.3	5.2
DPC	668	1,650	57	930	2,410	60	1,295	3,500	62	2,513	7,450	68	6.9	7.8
IIGE	1,016	2,950	67	1,424	4,175	68	2,015	5,910	68	3,760	11,025	68	6.8	6.8
IPL	966	2,806	67	1,232	3,732	67	1,730	4,998	67	3,097	8,996	67	6.0	6.0
ISP	715	2,190	71	956	2,920	70	1,220	3,730	70	1,987	6,085	71	5.2	5.2
IELP-CIPCO	1,160	3,653	73	1,619	4,318	61	2,261	6,004	61	4,411	11,601	61	6.9	5.9
IPS	697	1,780 2/	59	924	2,361 2/	59	1,330	3,396 2/	59	2,500	6,386 2/	59	6.6	6.6
ISU	387	1,097	65	543	1,645	70	796	2,306	67	1,720	4,525	61	7.7	7.3
KCPL	1,830	5,447	69	2,508	7,462	69	3,435	10,222	69	6,449	19,191	69	6.5	6.5
MDU	282	766	63	324	874	62	402	1,084	62	633	1,707	62	4.1	4.1
MPL	1,300	4,441	79	1,677	5,652	78	2,171	7,207	76	2,912	9,602	76	4.1	3.9
Municipals 1/	2,206	5,750	60	2,885	7,519	60	3,684	9,602	60	6,000	15,638	60	5.1	5.1
MWPS	190	495	60	254	662	60	339	884	60	605	1,577	60	6.0	6.0
NPPD	1,473	4,018	63	1,939	5,358	64	2,481	6,974	65	3,975	11,600	67	5.1	5.4
NSP	6,095	15,730 2/	59	8,548	22,061 2/	59	11,989	30,943 2/	59	21,470	55,412 2/	59	6.5	6.5
OPPD	1,053	3,232	71	1,334	4,246	73	1,653	5,210	73	2,452	7,216	68	4.3	4.1
OTP	435	1,195	63	582	1,598	63	778	2,137	63	1,393	3,826	63	6.0	6.0
UE	5,906	15,393 2/	60	8,441	22,000	60	12,063	31,441 2/	60	24,636	64,211 2/	60	7.4	7.4
UPA RCPA	371	813	50	605	1,325	50	855	1,872	50	1,520	3,329	50	7.3	7.3
NCPA	166	364	51	249	545	50	334	731	50	545	1,194	50	6.1	6.1
Reg. 6	2,591	6,150	55	3,543	8,444	55	4,874	11,499	54	9,340	21,849 2/	54	6.6	6.5
Reg. 7	125	303	56	170	413	56	228	553	56	332	806	56	5.0	5.0
Total	33,151	89,565	62	45,941	123,484	62	63,689	170,895	62	119,953	319,884	61	6.6	6.6

1/ Minn., Iowa, Kansas, & Missouri (Other municipal loads assumed to be included in Coordinating Comm. Member loads).
2/ Not supplied by participant.

North Central Power Study

Comparison of North Central Power Study Basic Load Estimates with Federal Power Commission Load Data

Following is a comparison of load estimates for power supply areas within the boundaries of the North Central Power Study:

Summer of 1980 - mw

PSA	NCPS Est.	FPC Data
15	9,314	9,720
16	9,412	9,210
17	7,622	7,160
26	1,488	1,370
27	1,416	1,520
28	4,269	4,390
30	1,313	2,240
31	1,355	1,460
32	4,261	3,850
34	5,835	4.950
41	3,608	5,690
	49,893	51,560

Tabulation of Loads by Classes of Service

1980 Summer Peaks

	MW	% Total
Private	27,000	70
Cooperative	9,000	20
Municipal and Other	4,000	10
	40,000	100

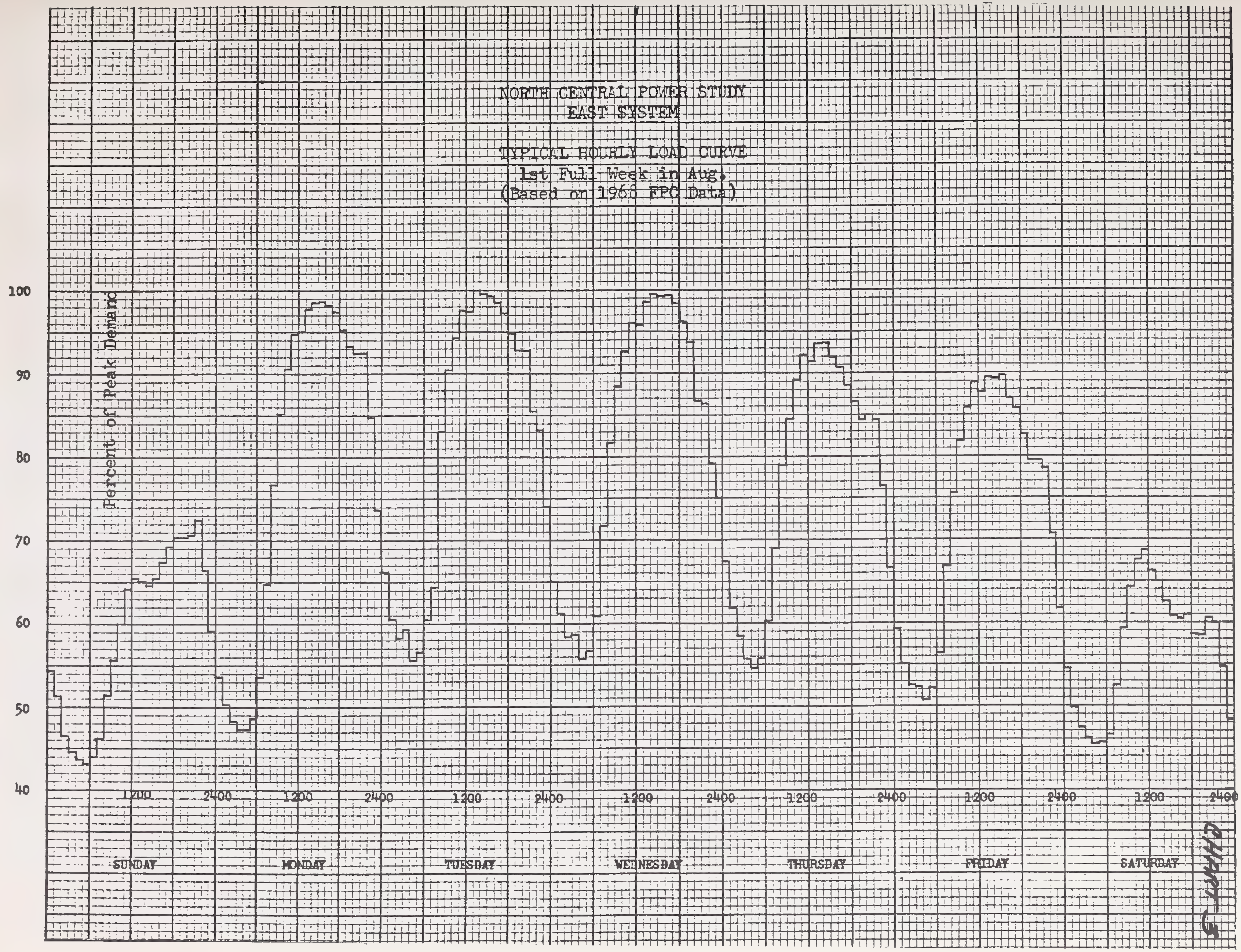


CHART 3
NORTH CENTRAL POWER STUDY
EAST SYSTEM
TYPICAL HOURLY LOAD CURVE
1st Full Week in Aug.
(Based on 1968 FPC Data)
Percent of Peak Demand
100
90
80
70
60
50
40
1200
2400
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY

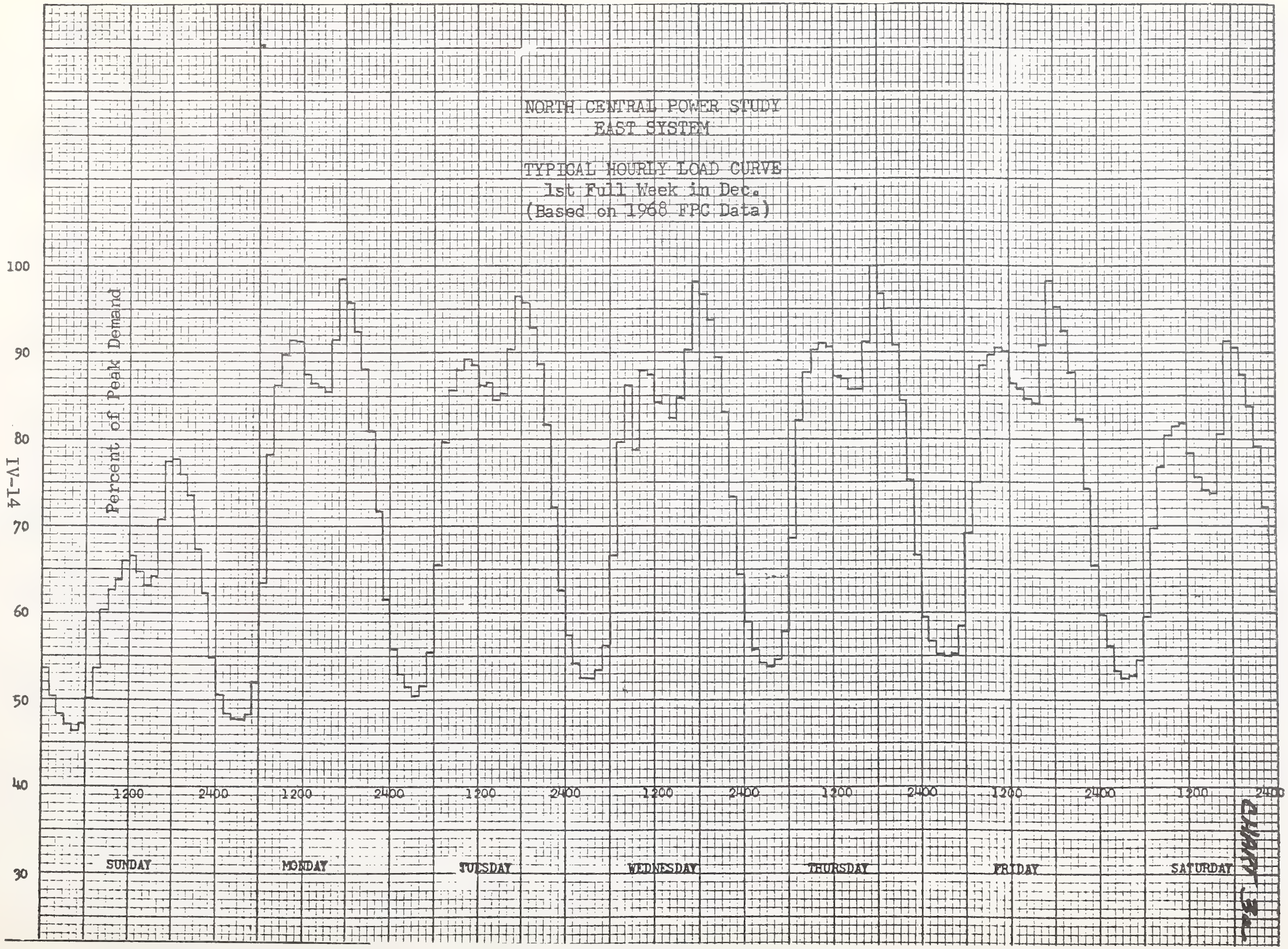

NORTH CENTRAL POWER STUDY
EAST SYSTEM
TYPICAL HOURLY LOAD CURVE
1st Full Week in Dec.
(Based on 1968 FPC Data)
Percent of Peak Demand
100
90
80
70
60
50
40
30
1200
2400
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
CHART 3a

CHART 4

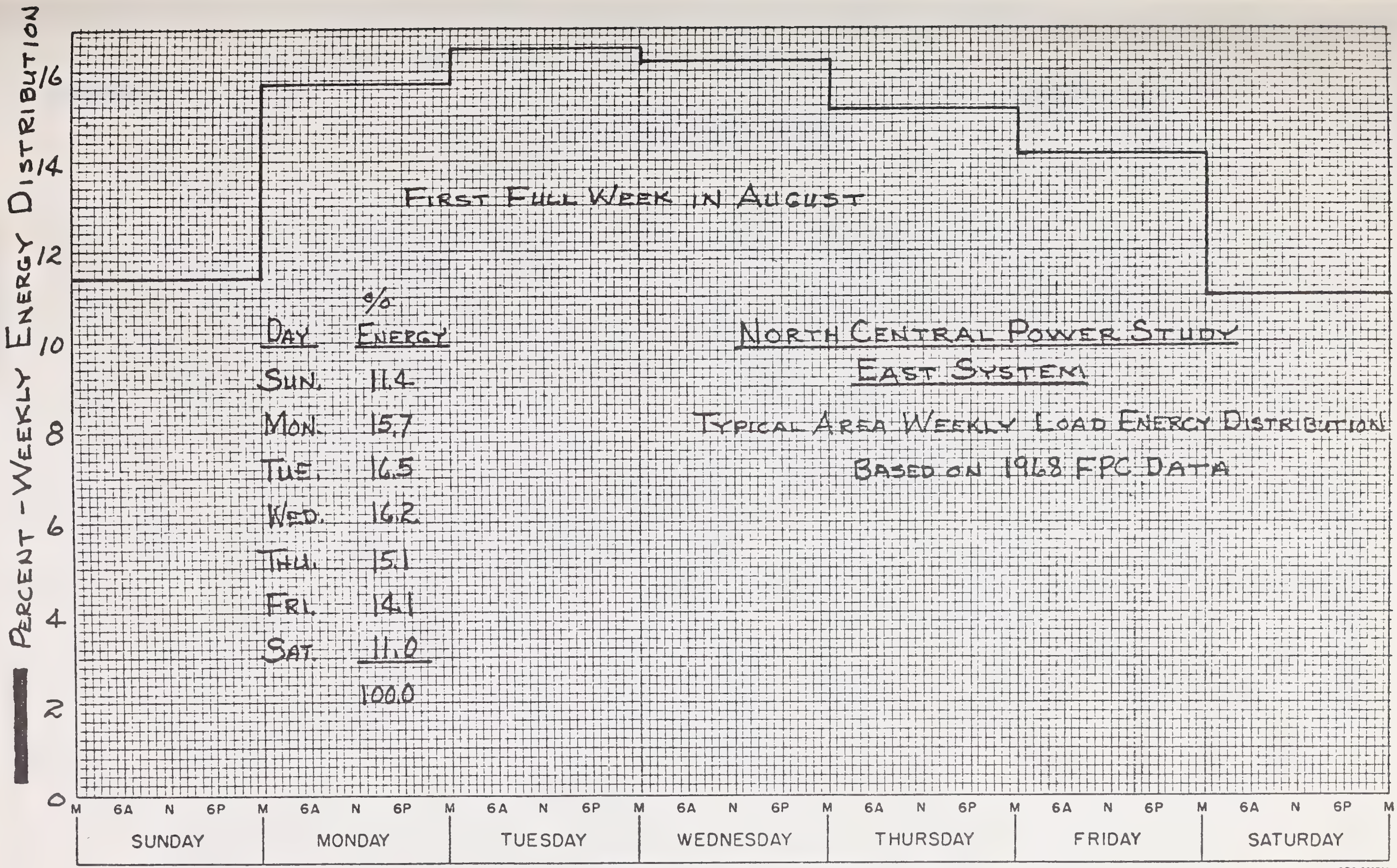

First Full Week in August
%
Day Energy
Sun. 11.4
Mon. 15.7
Tue. 16.5
Wed. 16.2
Thu. 15.1
Fri. 14.1
Sat. 11.0
100.0
North Central Power Study
East System
Typical Area Weekly Load Energy Distribution
Based on 1968 FPC Data
Percent - Weekly Energy Distribution
0
2
4
6
8
10
12
14
16
M 6A N 6P M 6A N 6P M 6A N 6P M 6A N 6P M 6A N 6P M 6A N 6P M 6A N 6P M
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
GPO 858718

CHART 4a

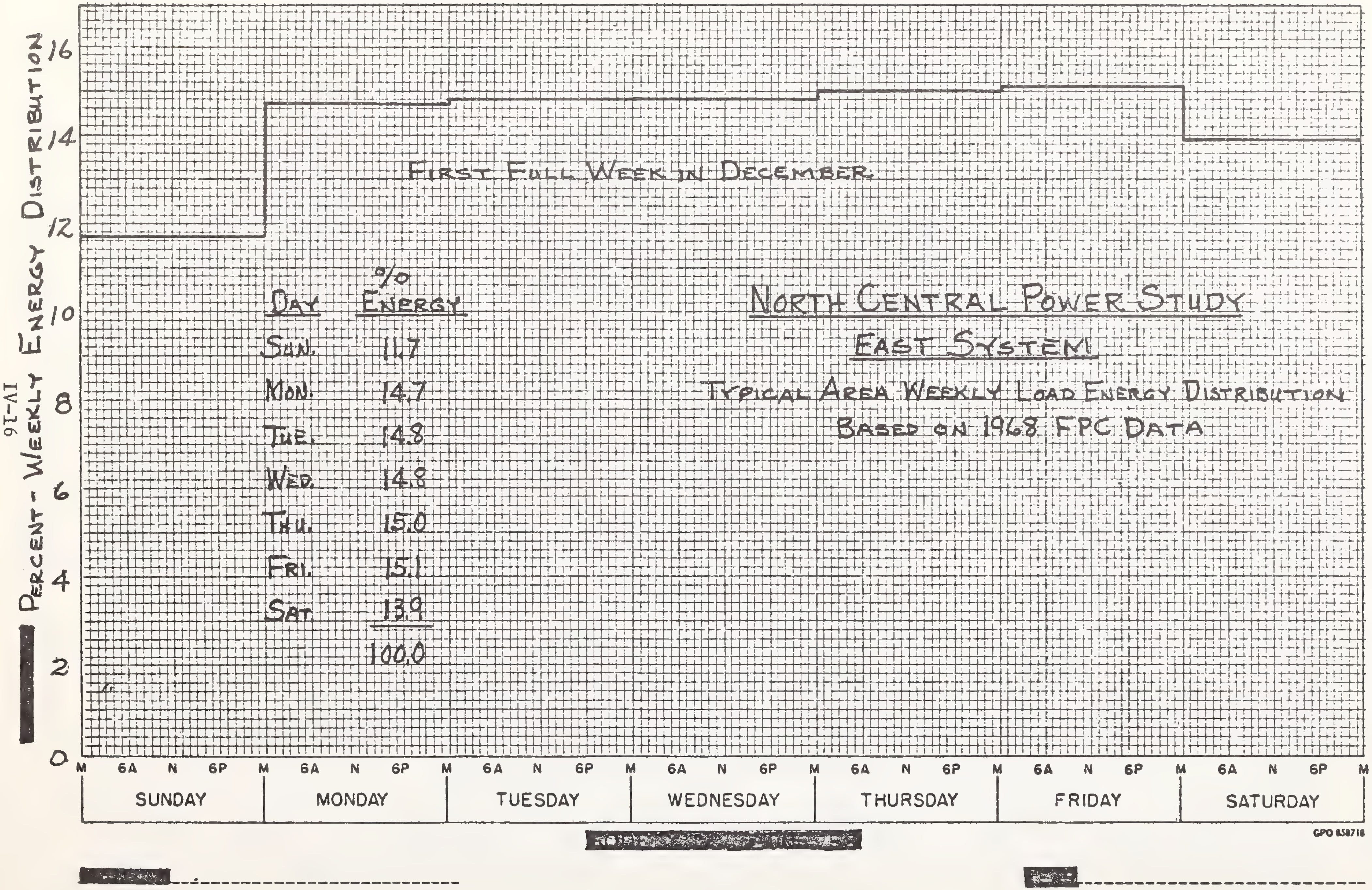

NORTH CENTRAL POWER STUDY
EAST SYSTEM
TYPICAL AREA WEEKLY LOAD ENERGY DISTRIBUTION
BASED ON 1968 FPC DATA
FIRST FULL WEEK IN DECEMBER
DAY
% ENERGY
SUN. 11.7
MON. 14.7
TUE. 14.8
WED. 14.8
THU. 15.0
FRI. 15.1
SAT. 13.9
100.0
PERCENT - WEEKLY ENERGY DISTRIBUTION
0
2
4
6
8
10
12
14
16
M 6A N 6P
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
GPO 858718
[redacted]

CHART 5

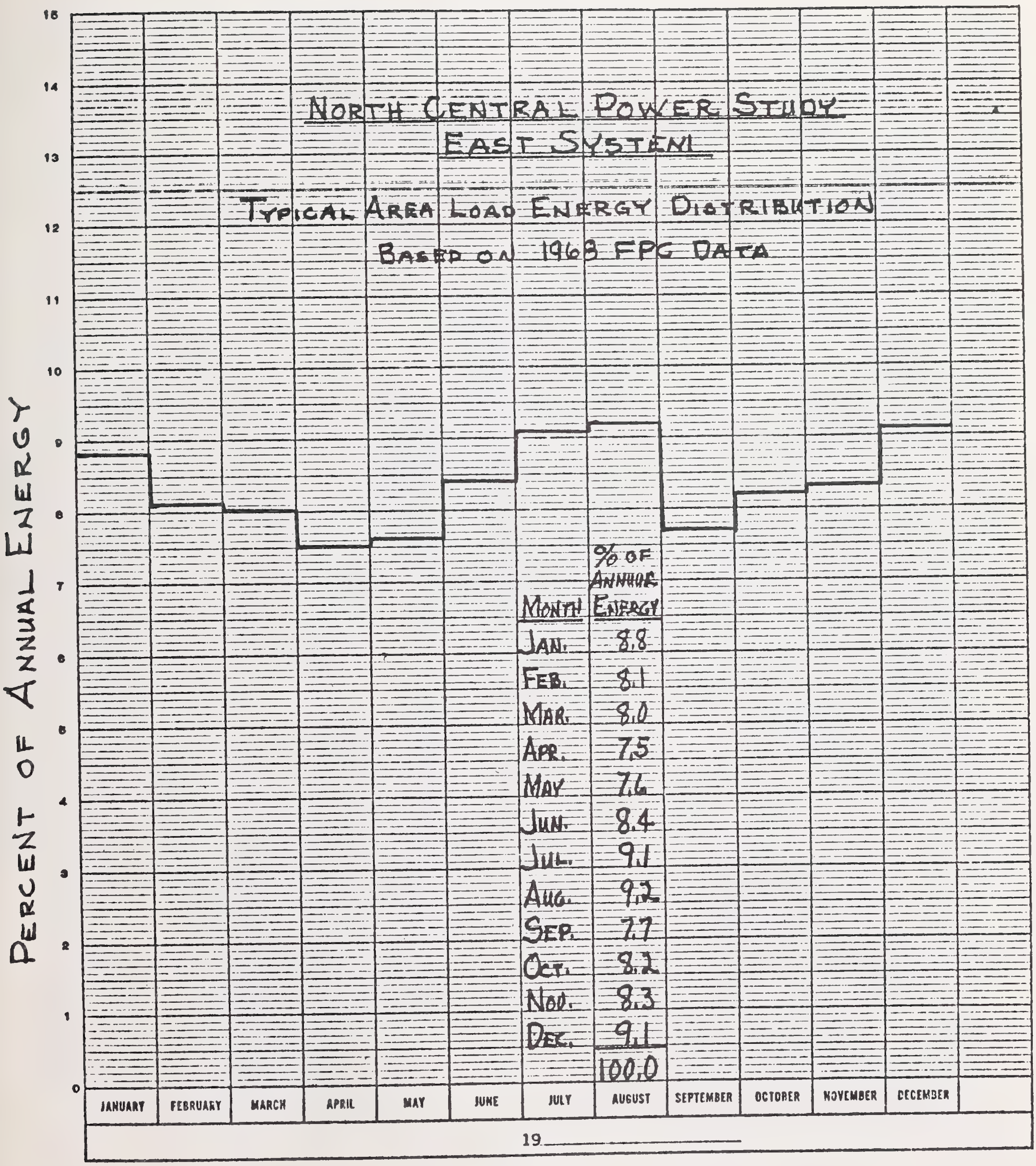
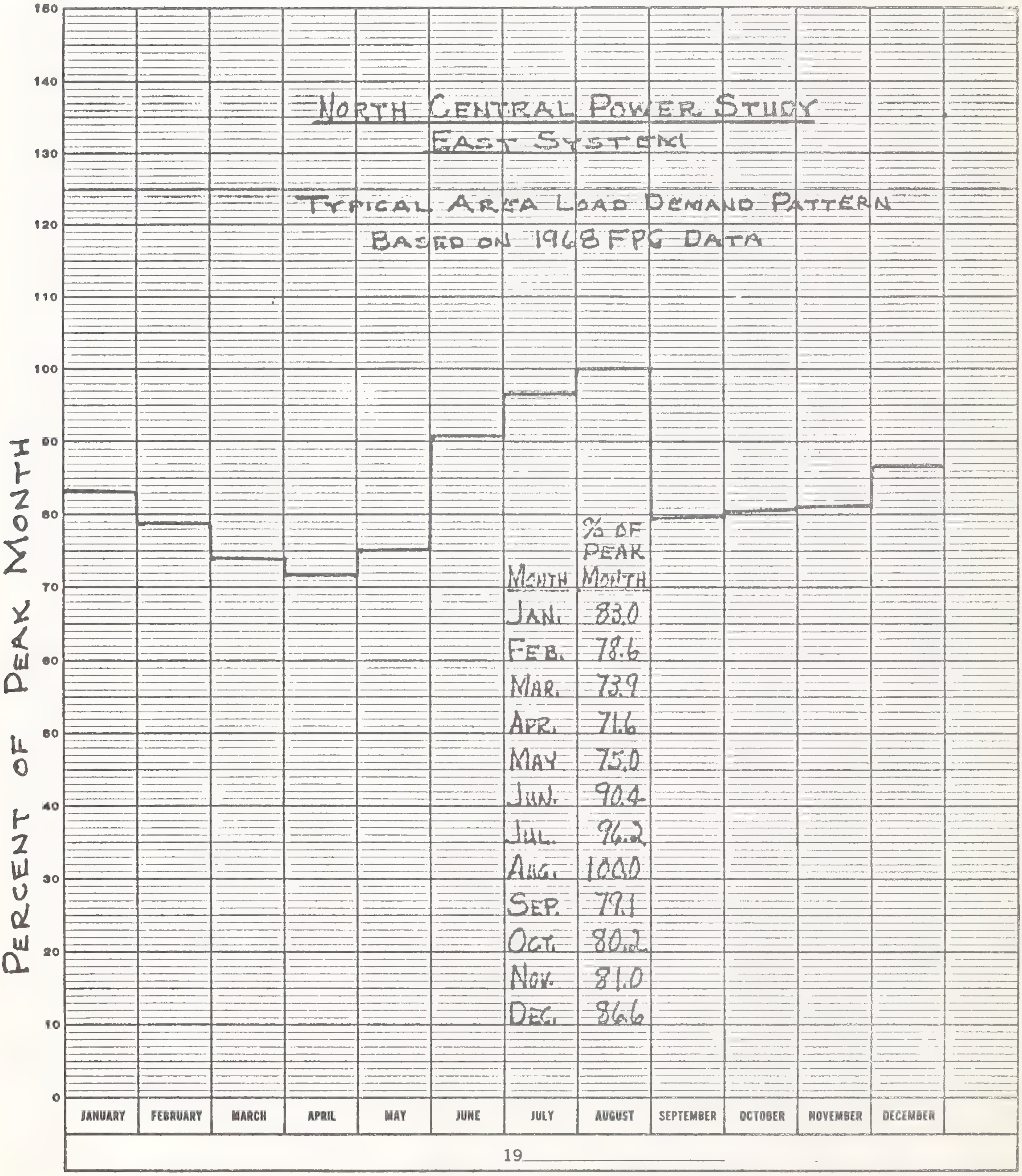
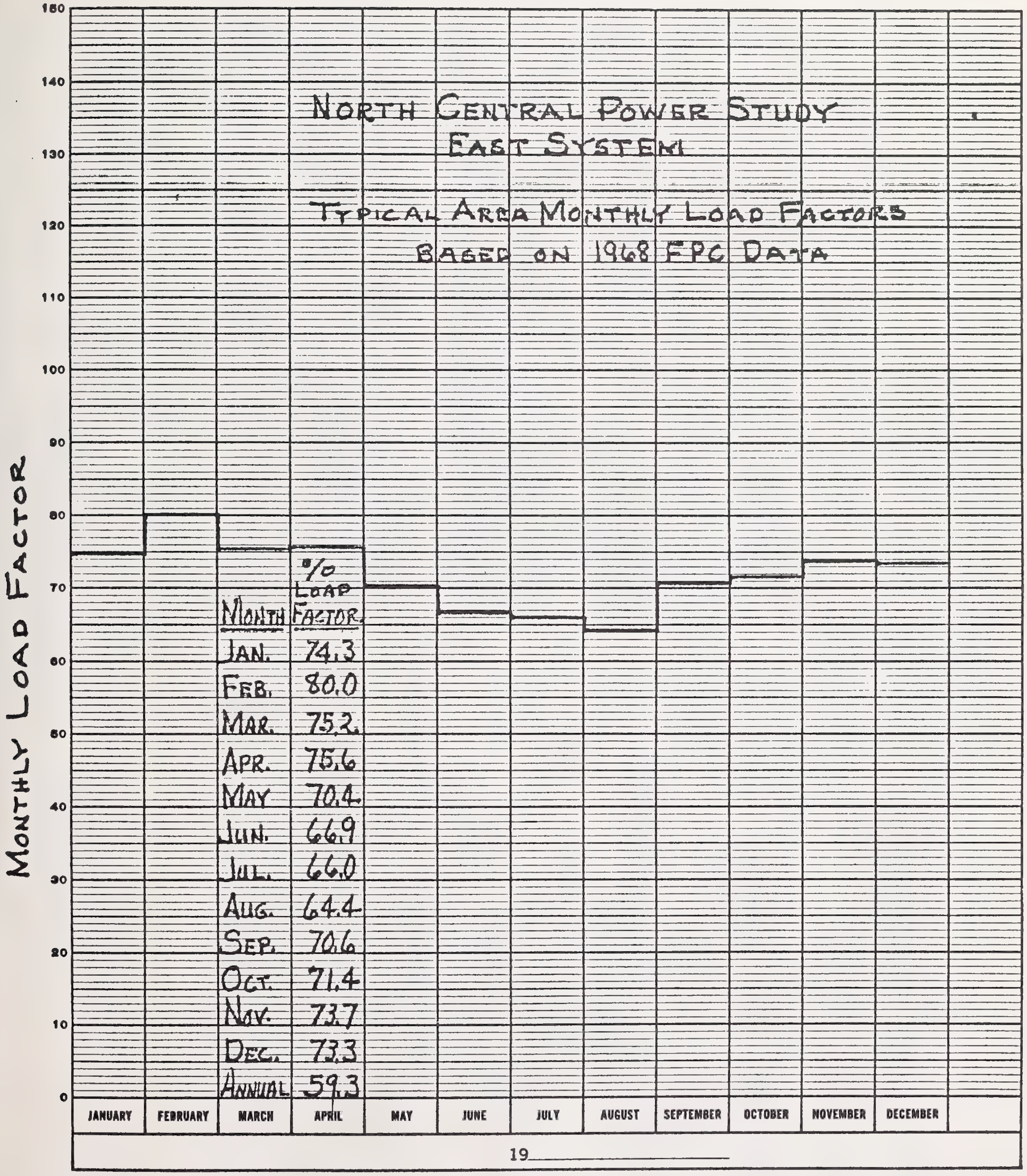

NORTH CENTRAL POWER STUDY
EAST SYSTEM
TYPICAL AREA LOAD ENERGY DISTRIBUTION
BASED ON 1968 FPC DATA
PERCENT OF ANNUAL ENERGY
MONTH % OF ANNUAL ENERGY
JAN. 8.8
FEB. 8.1
MAR. 8.0
APR. 7.5
MAY 7.6
JUN. 8.4
JUL. 9.1
AUG. 9.2
SEP. 7.7
OCT. 8.2
NOV. 8.3
DEC. 9.1
100.0
JANUARY
FEBRUARY
MARCH
APRIL
MAY
JUNE
JULY
AUGUST
SEPTEMBER
OCTOBER
NOVEMBER
DECEMBER
19

CHART 6


NORTH CENTRAL POWER STUDY
EAST SYSTEM
TYPICAL AREA LOAD DEMAND PATTERN
BASED ON 1968 FPC DATA
PERCENT OF PEAK MONTH
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
MONTH
% OF PEAK MONTH
JAN. 83.0
FEB. 78.6
MAR. 73.9
APR. 71.6
MAY 75.0
JUN. 90.4
JUL. 96.2
AUG. 100.0
SEP. 79.1
OCT. 80.2
NOV. 81.0
DEC. 86.6
JANUARY
FEBRUARY
MARCH
APRIL
MAY
JUNE
JULY
AUGUST
SEPTEMBER
OCTOBER
NOVEMBER
DECEMBER
19


NORTH CENTRAL POWER STUDY
EAST SYSTEM
TYPICAL AREA MONTHLY LOAD FACTORS
BASED ON 1968 FPC DATA
MONTHLY LOAD FACTOR
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
MONTH
% LOAD FACTOR
JAN. 74.3
FEB. 80.0
MAR. 75.2
APR. 75.6
MAY 70.4
JUN. 66.9
JUL. 66.0
AUG. 64.4
SEP. 70.6
OCT. 71.4
NOV. 73.7
DEC. 73.3
ANNUAL 59.3
JANUARY
FEBRUARY
MARCH
APRIL
MAY
JUNE
JULY
AUGUST
SEPTEMBER
OCTOBER
NOVEMBER
DECEMBER
19

East of Ties

North Central Power Study

Sheet II

Area Load-Generation Summary

Reporting Entity Basin Electric

Date 11/20/70

Estimated Peak Loads	80 Summer	80/81 Winter	85 Summer	85/86 Winter	90 Summer	90/91 Winter	2000 Summer	00/01 Winter
1. Net Loads from Sheet 1	1,105	1,365	1,431	1,810	1,854	2,399	3,133	4,212
2. Est. Losses 6%	66	82	86	109	111	144	188	253
3. Input Requirement (1 + 2) 1/	1,171	1,447	1,517	1,919	1,965	2,543	3,321	4,465
4. Reserve Capacity Obligation 12%	141	174	182	230	236	305	399	536
5. Total Requirement (3 + 4)	1,312	1,621	1,699	2,149	2,201	2,848	3,720	5,001
6. Net Generating Capacity Owned or Planned *	683	683	683	683	683	683	683	683
Planned Interchange by Companies (+ or -)								
Co. Region #6 **	287.4	691.6	287.4	691.6	287.4	691.6	287.4	691.6
Co. Rushmore (Wyo.)	3.9	4.6	3.9	4.6	3.9	4.6	3.9	4.6
Co. Tri-State (Neb.)	60.7	41.8	60.7	41.8	60.7	41.8	60.7	41.8
Co.								
7. Total Purchase or Sales	352.0	738.0	352.0	738.0	352.0	738.0	352.0	738.0
8. Adjusted Net Capability (6 ± 7)	1,035.0	1,421.0	1,035.0	1,421.0	1,035.0	1,421.0	1,035.0	1,421.0
9. Surplus or Deficit (5 - 8)	(277.0)	(200.0)	(664.0)	(728.0)	(1,166.0)	(1,427.0)	(2,685.0)	(3,580.0)
10. If 9 is a deficit, what amount would you consider obtaining from a new North Central power source (max./min.)?	136.0	26.0	482.0	493.0	930.0	1,122.0	2,286.0	3,044.0
11. Scheduled Generation from Sheet 1 (mw)	683.0	683.0	683.0	683.0	683.0	683.0	683.0	683.0
12. Schedule Input (11 ± 7) (should be same as 3) + 10	1,171.0	1,447.0	1,517.0	1,919.0	1,965.0	2,543.0	3,321.0	4,465.0

Estimated Load Energy Requirements GWH Summer and Winter 2/		80 Summer	80/81 Winter	85 Summer	85/86 Winter	90 Summer	90/91 Winter	2000 Summer	00/01 Winter
	USBR	1,010	2,020	1,010	2,020	1,010	2,020	1,010	2,020
	Basin	2,351	1,940	3,344	3,232	4,630	4,940	8,523	10,200
	Total	3,361	3,960	4,354	5,252	5,640	6,960	9,533	12,220

1/ This should be equivalent to data submitted to the Federal Power Commission.

2/ Summer - May 1 through October 31
Winter - November 1 through April 30

* Includes 212 mw Basin Unit #1, 438 mw Unit #2, and 33 mw Central G&T, Minot.

** Includes 381.1 mw Class A allocation, 5.0 mw Central Mont. East of Ties, 280 mw peaking, and 25.5 mw Air Force. The summer allocation is held constant because of the load pattern.

North Central Power Study

Area Load-Generation Summary

Reporting Entity NSP

Date

Estimated Peak Loads	80 Summer	80/81 Winter	85 Summer	85/86 Winter	90 Summer	90/91 Winter	2000 Summer	00/01 Winter
1. Net Loads from Sheet 1	6,852	6,035	9,610	8,464	13,480	11,872	25,590	21,260
2. Est. Losses	68	60	96	84	133	117	252	210
3. Input Requirement (1 + 2) 1/	6,920	6,095	9,706	8,548	13,613	11,989	25,842	21,470
4. Reserve Capacity Obligation	830	731	1,165	1,026	1,633	1,439	3,101	2,576
5. Total Requirement (3 + 4)	7,750	6,826	10,871	9,574	15,246	13,428	28,943	24,046
6. Net Generating Capacity Owned or Planned	5,452	5,640	5,452	5,640	5,452	5,640	5,452	5,640
Planned Interchange by Companies (+ or −)								
Co.								
Co.								
Co.								
Co.								
7. Total Purchase or Sales								
8. Adjusted Net Capability (6 ± 7)	5,452	5,640	5,452	5,640	5,452	5,640	5,452	5,640
9. Surplus or Deficit (5 − 8)	-2,298	-1,186	-5,419	-3,934	-9,794	-7,788	-23,491	-18,406
10. If 9 is a deficit, what amount would you consider obtaining from a new North Central power source (max./min.)?	500	500	1,100	1,100	1,700	1,700	4,600	4,600
11. Scheduled Generation from Sheet 1 (mw)	5,086	5,230	5,086	5,230	5,086	5,230	5,086	5,230
12. Schedule Input (11 ± 7) (should be same as 3)								

Estimated Load Energy Requirements		80 Summer	80/81 Winter	85 Summer	85/86 Winter	90 Summer	90/91 Winter	2000 Summer	00/01 Winter
GWH Summer and Winter 2/	Est. 50% S.L.F. 60% W.L.F.	15,129	15,730	21,219	22,061	29,764	30,943	56,503	55,412

1/ This should be equivalent to data submitted to the Federal Power Commission.

2/ Summer - May 1 through October 31
Winter - November 1 through April 30

NAMES OF ENTITIES

Assoc. E. Coop.	Associated Electric Cooperative
BEP Coop.	Basin Electric Power Cooperative
BHPL	Black Hills Power and Light Company
DPC	Dairyland Power Cooperative
IIGE	Iowa-Illinois Gas and Electric Company
IPL	Iowa Power and Light Company
ISP	Interstate Power Company
IELP-CIPCO	Iowa Electric Power Company-Central Iowa Power Cooperative
IPS	Iowa Public Service Company
ISU	Iowa Southern Utilities Company
KCPL	Kansas City Power and Light Company
MDU	Montana-Dakota Utilities Company
MPL	Minnesota Power and Light Company
Municipals	Eastern Area municipals whose load is not included with other entities
NWPS	Northwestern Public Service Company
NPPD	Nebraska Public Power District
NSP	Northern States Power Company
OPPD	Omaha Public Power District
OTP	Otter Tail Power Company
UE	Union Electric Company
UPA	United Power Association

Region 4, 6 or 7	United States Bureau of Reclamation
Colo-Ute	Colorado-Ute Electric Association, Inc.
IPC	Idaho Power Company
MPC	Montana Power Company
PSC Colo.	Public Service Company of Colorado
PPL	Pacific Power and Light Company
UPL	Utah Power and Light Company

V. Economics Committee

Purpose and Scope

The Economics Committee was formed to accumulate the cost data as developed by the other committees and develop an overall cost analysis for the various parts of this study. The Economics Committee was also directed to estimate the necessary property taxes and interest charges to apply during the construction period to complete the data developed by the other committees.

In the course of the study, the Coordinating Committee decided that the Gillette-Colstrip area should be used for study purposes as the site for the generation complex development. As a result the Economics Committee has developed overall system costs only for the Gillette area sites.

The following sections summarize the economic factors for each portion of the overall development.

Water and Coal Deliveries

The water supply Task Force developed the anticipated costs of water delivery to the Gillette area for the various ultimate sizes of the generation complex. These costs are summarized in mills/kwh generated on Table III E-1 and assume that the generation complex uses 100 percent of the delivered water. These costs include both the annual revenue requirements on the capital expenditure and the operating costs such as labor, maintenance, and energy costs for the pumping.

The water supply costs were determined assuming Federal government construction and operation of the aqueducts and all associated equipment. The financial arrangements considered in this analysis were based on a 3.463 percent interest rate which is the rate applicable for fiscal year 1971 under provisions of the Water Supply Act of 1958, as amended. This rate was used for both interest during construction and to determine the annual revenue requirements on the capital investment assuming a 50-year life of the water supply facilities. A 50-year life can be used for the supply facilities even though the generating plant life has been assumed to be only 35 years. This is practical because the available coal in the Gillette area would allow two or more developments of the maximum size this study considered.

The pipeline size was optimized for each level of development. Therefore the costs shown on Table III E-1 cannot be used to determine the water supply costs during interim development of the generation complex.

The coal and byproducts Task Force has estimated coal costs in the Gillette area to be between 11 and 12 cents per million B.t.u.'s at the mine-mouth in 1970 prices. An additional .3 to .4 cents per million B.t.u.'s must be added to cover the cost of transporting the coal from the mine to the actual plant site. About .15 cent/MBTU must also be included for land reclamation. Including the above costs and assuming 5 percent annual escalation, the 1975 fuel costs would be about 16 cents/MBTU at the generator.

Generation Plant Cost

The basic generating unit capital costs were developed by the Thermal Generation Task Force. The construction period and the portion of the total plant costs that would be spent each year was also furnished by the Thermal Generation Task Force. To these base costs the Economics Committee has added the property tax and interest charges that would be incurred during construction. A nominal 1 percent annual property tax rate during the construction period was based on consideration of the rural nature of the area, and the magnitude of the generating complex. This tax rate assumes that the current year's taxes are based on the total expenditure for all previous years. As a result the total property taxes paid during the construction period amount to approximately 1.4 percent of the total cost.

A nominal 7 percent rate was used as the average interest rate during the construction period, considering the mix of participants and average interest rates for investor-owned utilities, cooperatives, and municipals. This was applied each year to the total construction of all previous years plus one-half of the current year's expenditures based on the premise that the construction expenditures would be uniform throughout the year. The total interest charged during construction amounts to about 13 percent of the total investment. The generating plant cost for two 500 mw units and two 1,000 mw units are summarized on Table III E-2.

As is shown on Table III E-2, the cost of providing a 60-day emergency coal storage stockpile is assumed to be capitalized and is included with the total cost of the plant. Although this method of accounting for the cost of providing an emergency coal supply is not precisely accurate, for the purposes of this study it does provide a reasonable method of accounting for a rather significant cost item.

Annual operating costs were obtained primarily from the Thermal Generating Task Force with an additional 30 percent adjustment to the O&M costs to include administration and general expenses and all labor fringe benefits and are summarized on Table III E-3. The major operating expenses besides fuel are the operating and maintenance labor and the cost of ash disposal.

The required capital investment and annual operating costs for the two pumped storage sites selected for this study are summarized on Table III E-4; the cost information having been obtained primarily from the Hydrogeneration Task Force. Property taxes and interest charges during the construction period have been allocated in an identical manner as for thermal generation following the construction schedule provided by the Hydrogeneration Task Force.

The pumping energy cost as determined by the Hydrogeneration Task Force is approximately 1.5 times the energy production cost of the thermal development. The cost of this energy has been calculated as the net cost of energy at the mine-mouth plant adjusted for 1 percent nominal transmission losses to deliver this power to the pumped storage site. The annual O&M costs are based on 2,000 hours generating and 3,000 hours pumping and include administrative and general expenses and labor fringe benefits. These are shown on Table III E-4 in terms of energy actually generated.

Transmission Costs

The total construction costs for the transmission system necessary for reliable operation at the various levels of generation were obtained from the Transmission Committee. To these costs again have been added the property taxes and interest charges during the construction period. The required capital expenditure and annual operating and maintenance costs are summarized on Table III E-5 for both the Eastern and Western Systems.

Development Levels

The guidelines for this study were to obtain the total system costs for various levels of development of the generation. No attempt was made to determine the timing of progression from one stage of development to the next. The total investment and total annual operating costs for each level of development are summarized on Table III E-6 and III E-7, respectively. These costs are based on the actual capacity and energy delivered to the participating system as determined by the Transmission Committee and include the additional generators required at the coal fields for maintenance.

Transmission Responsibility

For large development in the coal field where the more distant users must provide transmission to their receiving points, the likelihood is that local alternatives may tend to be more attractive for these users; yet, without these added power requirements, the project in its large size probably cannot be justified. Therefore, a method of assigning transmission responsibility has been developed which is referred to as a modified kw mile method. In this approach, three-fourths of the ownership and operating responsibility for the entire transmission system is shared by all users in proportion to their straight-line distance from the generating complex times their kw ownership in the generating complex and one-fourth of the transmission system is shared in by all users in proportion to their kw ownership in the generating complex.

Alternative methods for sharing costs are also possible and may prove more feasible than the modified kw-mile scheme chosen for presentation in this report. Essentially, all large power users in the eastern North Central Power Study area are situated in the eastern portion of that area; therefore, in order to economically justify a large power supply complex on the study area coal fields, it will be necessary to make the program as attractive as possible to these larger utilities. This can be done to some extent by allocating the cost of participation in the transmission programs on an average rate basis. Under this concept pro rata costs of transmission would be shared equally, kilowatt for kilowatt, whether the participant is within 100 or 600 miles of the plant site.

Method of Analysis by the Parties

Application of the kw-mile approach requires that a model first be developed which quantitatively describes the weighted usage of the transmission system which then is used as the denominator in each party's assessment of the attractiveness of this development. Because the power is not continuously extractable from the line, but is available only at discrete points, this calculation must be based upon the substation delivery points from which the parties will receive power. A diagram depicting the projected power flow for the 4,000 mw plan together with the estimated transmission mileages involved is shown in Figure III E-1. The approximate air mileages, as differentiated from transmission mileages, between the Gillette-Colstrip area and the various delivery points are shown on Table III E-8. The assumed deliveries at each point for the 4,000-mw plan and the 50,000-mw plan are also shown on Table III E-8. From this table, the weighted kw-mile figure is developed and from this each party making an ownership participation analysis can determine the substation from which its power will be received and the appropriate kw-mile factor. An example of this application follows.

Oahe is 260 miles from Gillette with an assumed delivery of 90 mw. Therefore, the factor for Oahe is 23,400 mw-miles. Total is 1,843,550 mw-miles resulting in the Oahe delivery point share of the total transmission are:

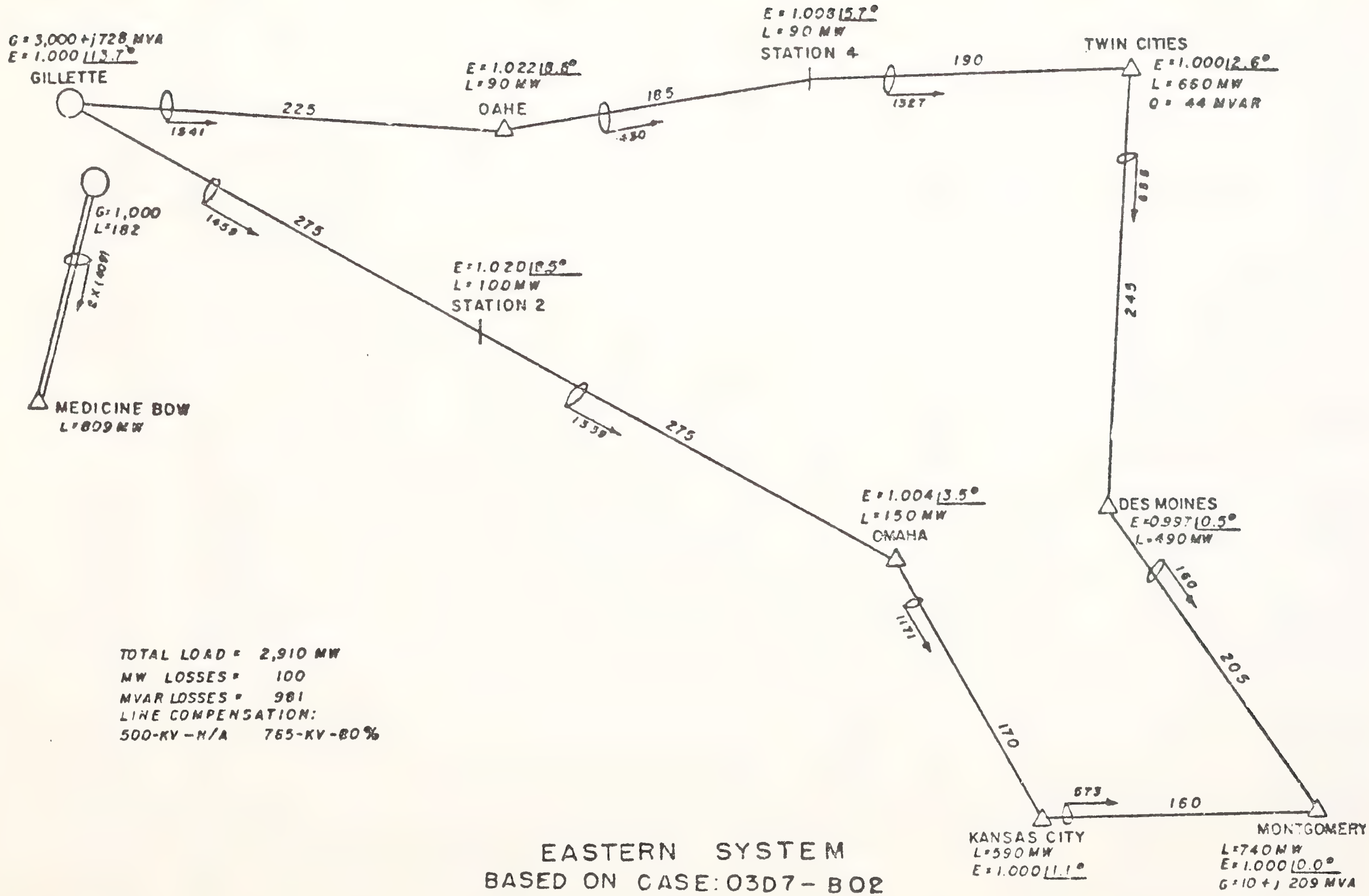
$$.25 \times \frac{90 \text{ mw (Oahe)}}{2{,}910 \text{ mw (Total)}} + .75 \times \frac{23{,}400 \text{ mw-miles (Oahe)}}{1{,}843{,}550 \text{ mw-miles (Total)}} = .01725$$

Therefore, a utility receiving 90 mw at Oahe would be responsible for about 1.7 percent of the total transmission system investment and transmission operating costs. The percentage share for each delivery point using the formula and the 4,000-mw and 50,000-mw plans are shown on Table III E-9.

It must be appreciated that proposed overall participation in the generating complex may vary substantially from the model shown. It is anticipated then that the responses to this report will be used in an iterative process to determine a new model and that this new model then will be used to elicit further response. Additionally, the pattern of responses may ultimately require a different ratio than the one-fourth/three-fourths weighting to make this development feasible. Because of this expectation, the 4,000-mw and 50,000-mw developments only are being offered for evaluation by the parties. However, to provide a basis for knowing the effect of further development, the curve in Figure III E-2 has been derived which shows the relationship between the various levels of generation and the total transmission investment per kw. This curve shows a continuing reduction in this factor. It follows then that the responsibility for participating investment in transmission will decrease a like percentage, which can be used in the overall analysis by the parties.

Figures III E-3 and III E-4 present the basic curves by which each party may determine the preliminary assessment of the cost per kwhr for his participation in the 4,000-mw development. Figures III E-5 and III E-6 present the curves for the 50,000-mw development. In each, the family of curves for varying levelized annual requirements includes that for the composite annual revenue requirement of 11.3 percent. This composite annual revenue requirement rate has been developed as shown on Table III E-10, assuming 50 percent of the project would be sponsored by investor-owned utilities, 35 percent by cooperatives or public power districts and 15 percent by municipals.

The procedure then is for a system to determine its location on the distance-axis of Figures III E-3 through E-6. By properly interpolating between the percent revenue requirement curves, its total cost per kwhr is found. As an example, in Figure III E-3, the Twin Cities are 575 miles from the generating complex. With annual revenue requirements of 10 percent, the total energy cost is 9.25 mills/kwh. With a rate of return requirement of 15 percent, the total energy cost is 12.7 mills/kwh.



EASTERN SYSTEM
BASED ON CASE: 03D7 - B02
LINE TO KANSAS CITY THROUGH GERING
REROUTED THROUGH OMAHA

Figure E1

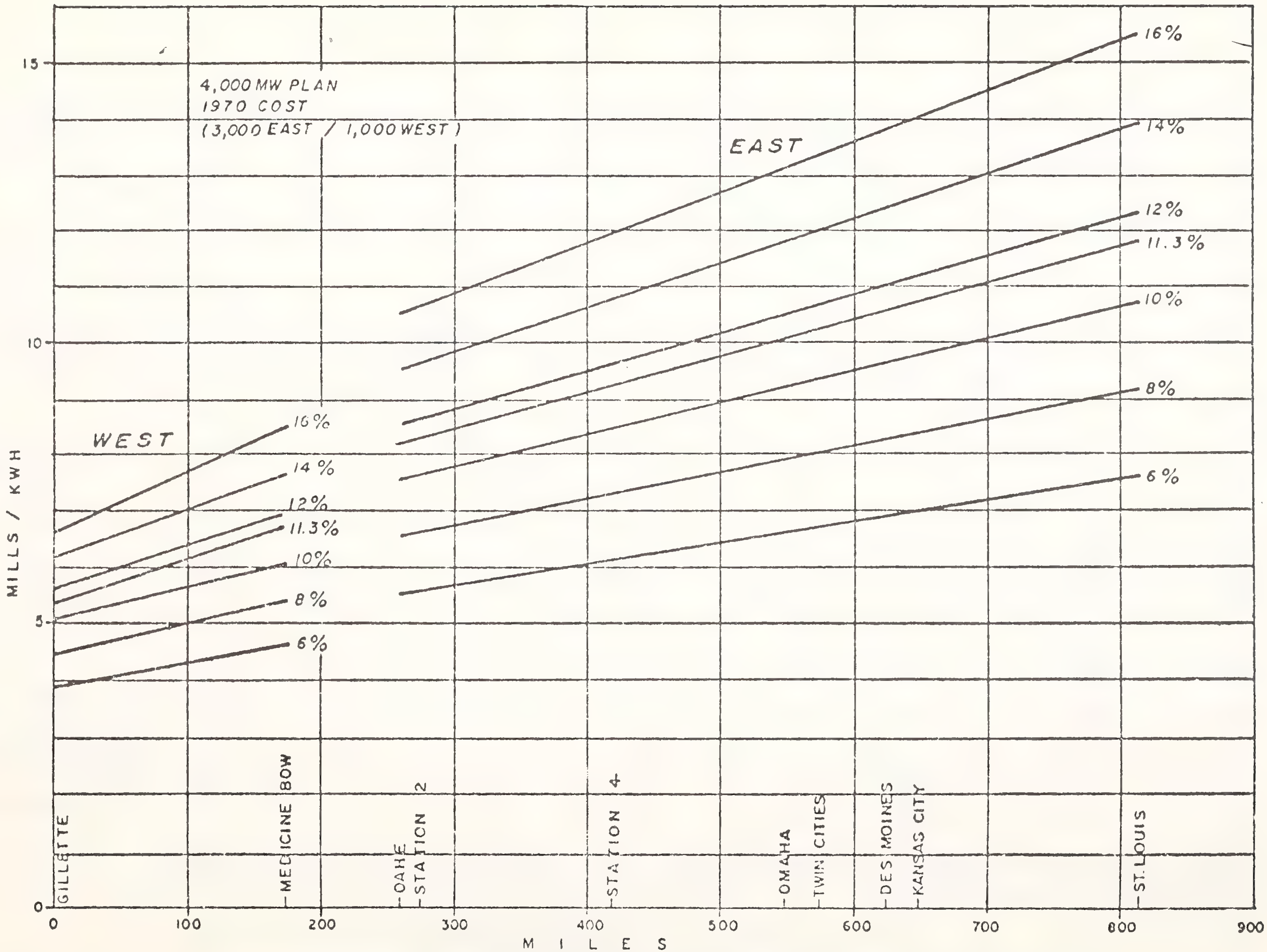
Table E-2

Summary of Capital Investment Required for Development

($1,000,000)

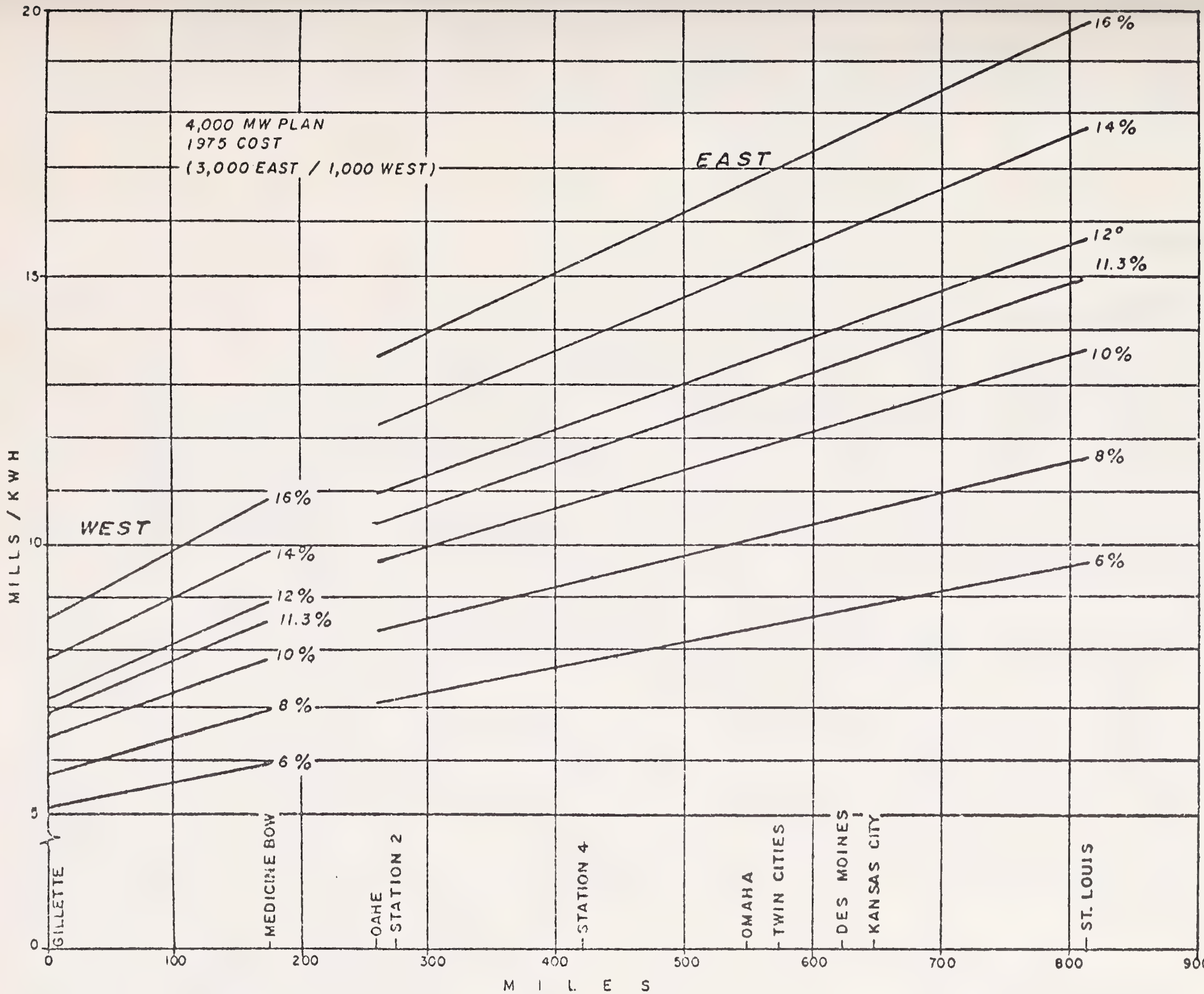
	Western System			Eastern System				
	1 000 mw	3 000 mw	10 000 mw	3 000 mw	10 000 mw	20 000 mw	40 000 mw	43 000 mw
Generating Plant*	183	582	1 723	549	1 668	3 252	6 378	6 923
Transmission System	87	183	361	963	1 734	2 775	4 923	5 513
Total 1970 Costs	270	765	2 084	1 512	3 402	6 027	11 301	12 436
Total 1975 Costs	345	976	2 659	1 929	4 342	7 691	14 421	15 870
Net Capacity to participating Systems (mw)	991	2 964	9 817	2 900	9 489	18 734	37 296	41 136
Total 1970 $/kw	272	258	212	521	358	321	303	302
Total 1975 $/kw	347	329	271	665	457	410	387	385

*Additional units required for maintenance are shared by Western and Eastern systems in proportion to share of complex.

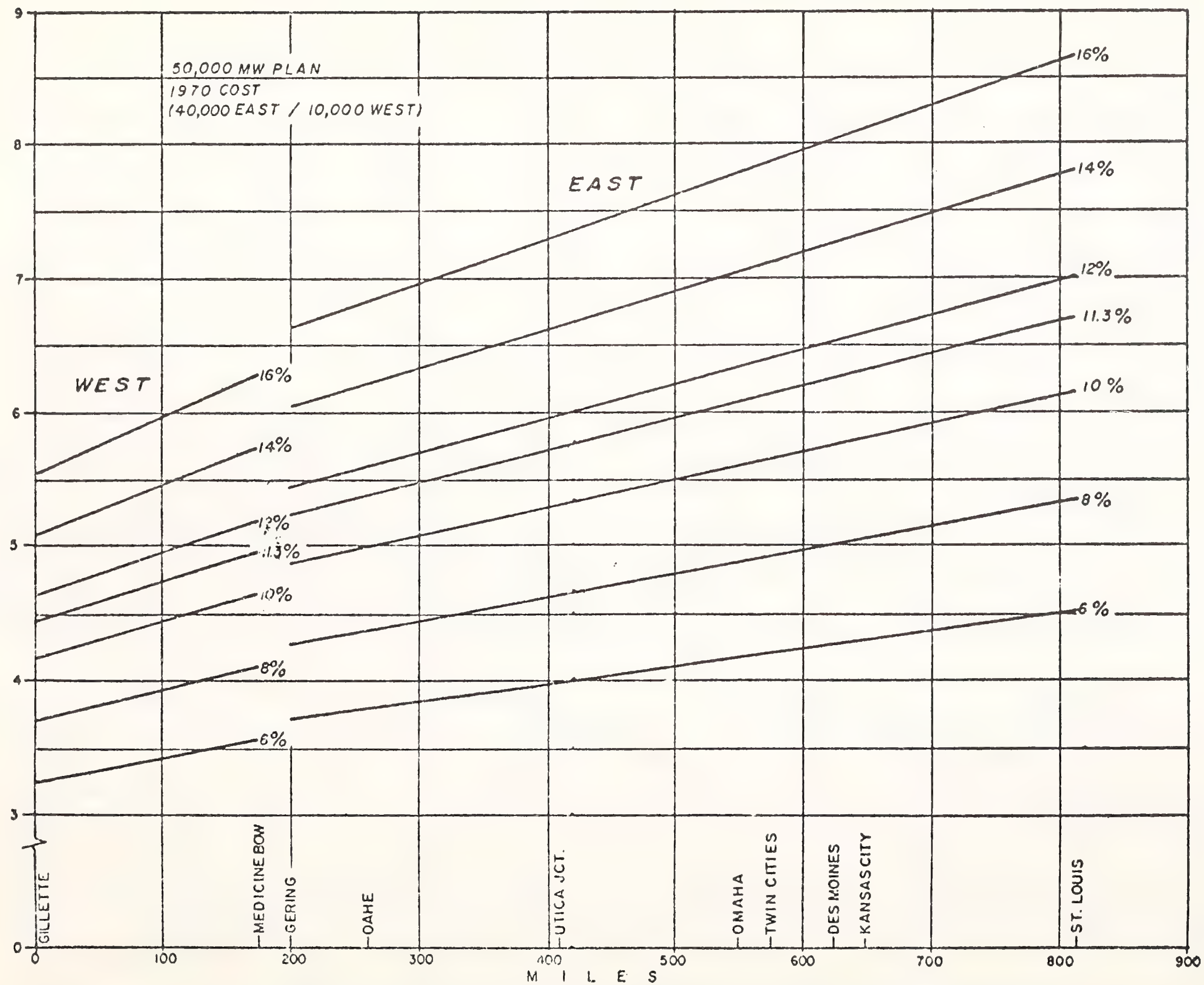


TOTAL PARTICIPATION COSTS FOR VARIOUS FIXED CHARGE RATES

Figure E-3

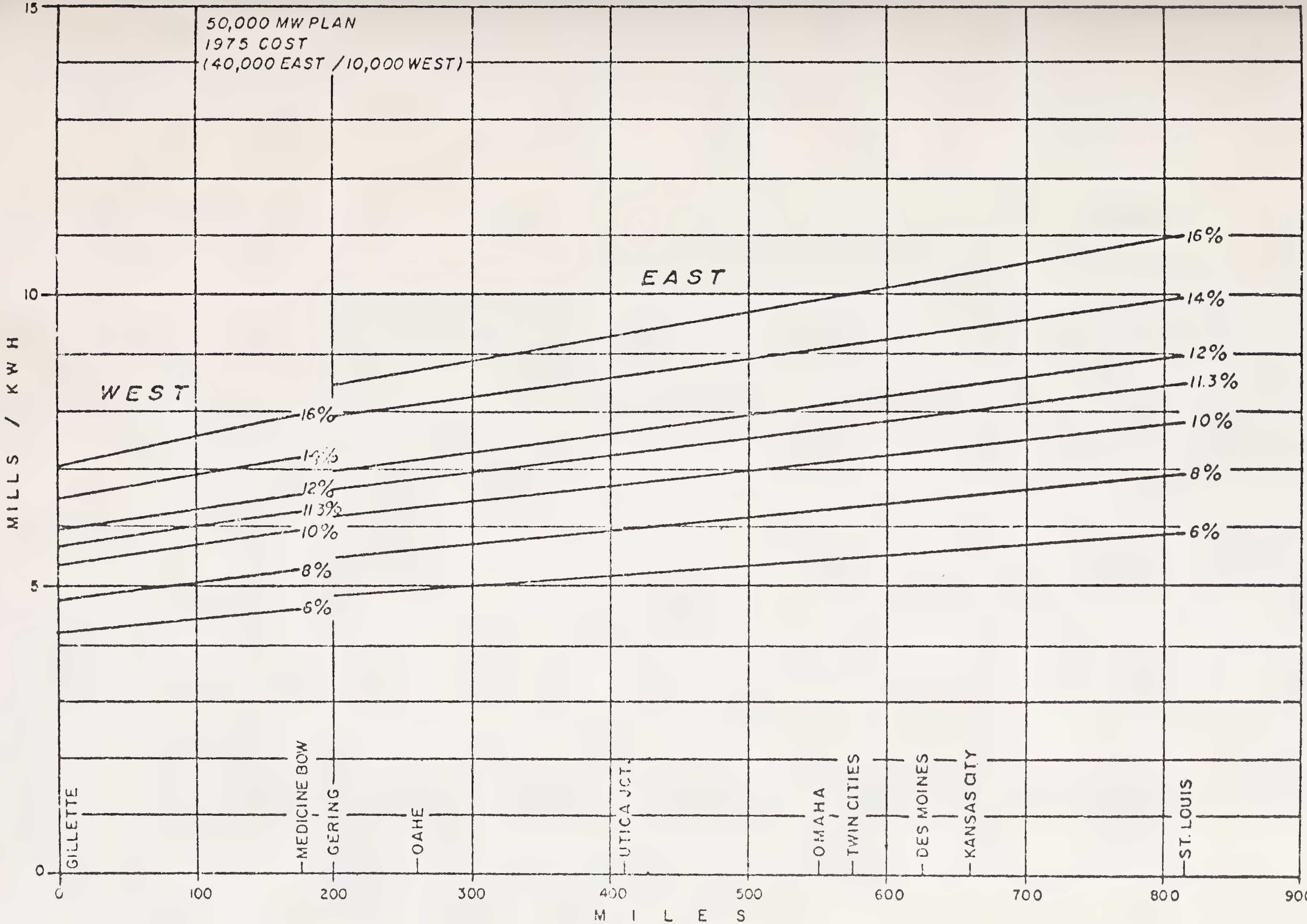


TOTAL PARTICIPATION COSTS FOR VARIOUS FIXED CHARGE RATES
Figure E-4



TOTAL PARTICIPATION COSTS FOR VARIOUS FIXED CHARGE RATES

Figure E-5



TOTAL PARTICIPATION COSTS FOR VARIOUS FIXED CHARGE RATES

Figure E–6

Table E-7
Summary of Annual Energy Production Cost
($1,000)

	Western System			Eastern System				
	1 000 mw	3 000 mw	10 000 mw	3 000 mw	10 000 mw	20 000 mw	40 000 mw	43 000 mw
Cooling Water	2 928	5 616	14 365	8 803	18 673	32 039	57 316	57 316
Fuel	8 866	28 560	93 198	26 656	92 092	184 660	368 200	368 200
O&M on Plant	4 396	14 160	32 871	13 216	32 158	53 954	112 084	116 830
Ash Disposal	745	2 400	8 070	2 240	7 980	16 100	32 200	32 200
O&M on Transmission	700	1 800	3 600	8 000	15 000	24 000	43 000	48 000
Total 1970 Prod Cost	17 635	52 536	152 104	58 915	165 903	315 753	612 800	622 546
Total 1975 Prod Cost	22 508	67 052	194 130	75 193	211 742	402 996	782 117	794 555
Energy Delivered to System (GWH)	7 440	23 730	79 300	21 730	75 920	151 360	301 300	298 100
Prod 1970 mills/kwh	2.37	2.21	1.92	2.71	2.19	2.09	2.03	2.09
Prod 1975 mills/kwh	3.03	2.83	2.45	3.46	2.79	2.66	2.60	2.67

Table E-8

Delivery Points Assumed in Study

Delivery Point	Air Mileage from Gillette (miles)	Power Delivered to this Point (mw): 3 000 mw Development	Power Delivered to this Point (mw): 4,000 mw Development
Eastern			
Oahe	260	90	1 200
Station No 4	420	90	0
Twin Cities	575	660	8 560
Des Moines	625	490	6 340
St Louis	815	740	9 136
Kansas City	650	590	7 580
Omaha	550	150	1 920
Station No 2	275	100	0
Gering	200	0	1 360
Utica Jct	410	0	1 200
Sum of mw-miles		1,843,550	23,357,340
TOTAL		2 910	37 296

Delivery Point	Air Mileage from Gillette (miles)	1 000 mw Development	10 000 mw Development
Western			
Gillette	0	182	1 822
Medicine Bow	175	809	7 995
Sum of mw-miles		141,575	1,399,125
Total		991	9817

Table E-9
Approximate Share of Transmission

Delivery Point	% Responsibility 300 mw Plan	40,000 mw Plan
Eastern		
Oahe	1.725	1.809
Station No 4	2.311	0
Twin Cities	21.109	21.519
Des Moines	16.669	16.956
St Louis	30.893	30.000
Kansas City	20.670	20.879
Omaha	4.645	4.673
Station No 2	1.978	0
Gering	0	1.784
Utica Jct	0	2.382
Total	100.000	100.000

	1000 mw Plan	10,000 mw Plan
Western		
Gillette	4.640	4.640
Medicine Bow	93.360	93.360

Table E-10

Levelized Annual Revenue Requirements for Various Types of Utilities

	%					
	Federal	Municipal	Cooperative	Investor Owned	Composite	
Type of Financing & Proportion						
Bond	100	100	100	50		
Preferred Stock				15		
Equity				35		
Component of Revenue Requirement and Approximate % of Investment						
Bond	5.375	6.50	6.75	8.00		
Preferred	---	---	---	8.00		
Equity	---	---	---	12.00		
Total Return	5.375	6.50	6.75	9.40		8.04
Income Tax (Federal & State)	---	---	---	3.13		1.57
Depreciation	.990	.78	.74	.42		.59
Insurance	.100	.10	.10	.10	.10	
Total Revenue Requirement						10.30
Property Tax *						1.0
Total						11.30

*Based on expectations considering areas of construction and the large size of development.

VI. Coal and Coal Byproducts

The Task Force on Coal and Coal Byproducts of the Resources Committee of the North Central Power Study has developed a list of locations having strip coal reserves capable of supporting 1,000 mw or larger coal burning thermal generating plants at each site.

The basis for establishing the necessary reserves per 1,000 mw were as follows:

1. Assume 9,400 B.t.u. per net kwh.

2. Assume plant capacity factor of 85 percent.

3. Assume 35-year life at base load.

The Task Force recognizes that units do not normally operate as base load plants for this length of time. However, there exists a strong possibility it may be desirable for the new mine-mouth plants to serve as base load units for the longer period.

Limits used to define a strippable deposit in the west are: (1) minimum coalbed thickness of 5 feet unless a thinner coalbed, occuring as a rider seam, would be recovered during the mining operation; (2) overburden to coal ratio of less than 10 cubic yards of overburden to 1 ton of coal; and (3) total overburden thickness of less than 120 feet except where reserves occur in multiple beds or a thick single bed under overburden locally as much as 200 to 260 feet thick. Table III B-1.1 provides details on reserves, quality, seam thickness and overburden at the various sites. The exception to these overburden thickness criteria is the Sorenson deposit in Lincoln County, Wyoming. There, the Kemmerer Coal Company has started an open pit that would be 1 mile square with a high wall of 1,100 feet. Several thick coalbeds will be recovered at the favorable stripping ratio of 7 to 1. Maximum overburden and total tons for each deposit estimated by these criteria are shown in the appendix on the line with the deposit name.

The ground rules for the North Central Power Study requested that plant installations of 1,000, 3,000, 5,000, and 10,000 mw be considered. The Task Force agreed to consider that recoverable reserves from new strip developments would be 80 percent of the "proven" reserves. Proven reserves are defined as those reserves which have been located by either detailed or preliminary drilling operations. Table III B-1.2 shows the "proven" reserves of strippable coal of various B.t.u. contents required for the several plant sizes being considered.

Figure II E-1.1 shows the general location of the coal fields and generation support capability of the coal sites. Table III B-1.3 identifies the locations having sufficient strippable coal reserves to serve plants of the sizes requested. These locations were selected on the basis of extensive information supplied through the Bureau of Mines.

In regard to the supplying of byproducts from synthetic fuel plants using coal, the Task Force cannot predict when or where synthetic fuel plants will be erected. However, the following general statements can be made:

1. Synthetic fuel plants will be in direct competition with powerplants for the large (3,000 mw or larger capability) reserves of strippable coal.

2. The first application will probably be for the production of synthetic pipeline gas. However, it is anticipated that any such plants will probably not produce sufficient byproduct fuel to carry a 1,000 mw generating plant.

3. Synthetic liquid fuel plants of the minimum size of 100,000 barrels per day could each supply char adequate for a 1,500 mw base load powerplant.

4. Coal can be converted by several techniques to alternate fuels for powerplant use. These include solvent extraction to produce a reconstituted fuel with low ash and sulfur contents, production of synthetic liquid fuel, and production of either high or low B.t.u. gas. None of these have progressed to demonstration plant stage, and consequently no reasonable estimates of cost or reliability can be made. It is anticipated that such information will be available by 1976-1980, but the detailed study of alternate fuels was not assigned to the Task Force.

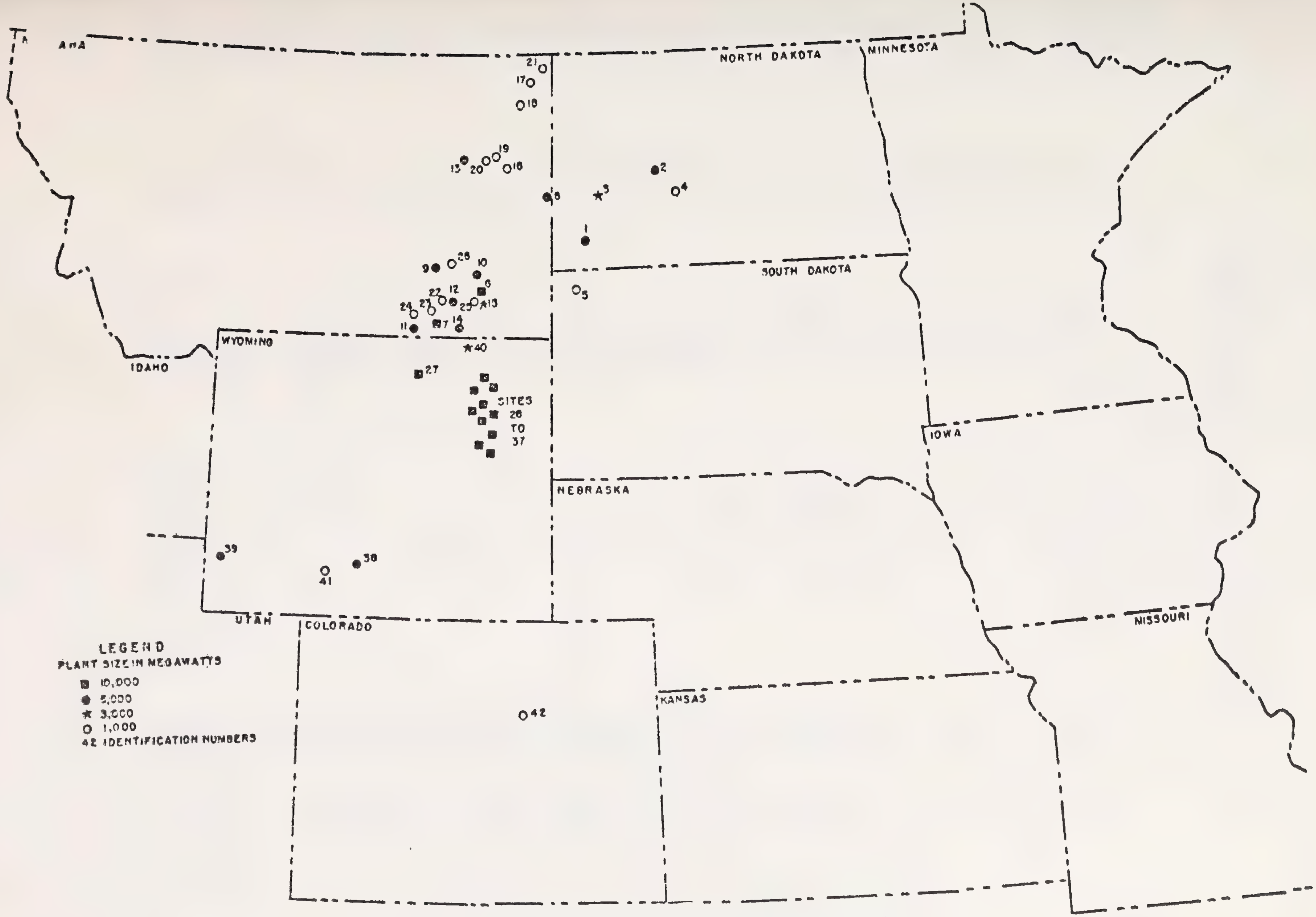
Coal prices are certain to escalate because of various factors including:

1. Labor.
2. Capital equipment.
3. Power.
4. Supplies.
5. Royalties and leases.
6. Governmental regulations on safety and environmental considerations.
7. Competitive demand for coal.

Each of these factors, and any others not presently recognized, is causing escalation in the cost of mine-mouth coal. The magnitude of each is impossible to evaluate with any precision, but it is believed that the cumulative effect will be about 5 percent per year compounded, in the period after 1970.

The estimated price of coal varies considerably across the various fields listed. It is recognized that other factors, such as location, availability of water, and environmental factors will color the cost per million B.t.u.'s at the mines.

Table III B-1.4 gives the estimated range of cost of coal from the various fields, based on 1970 costs at mine-mouth tipple excluding land reclamation costs.



LOCATION AND POWER GENERATION POTENTIAL OF
STRIPPABLE COAL DEPOSITS IN NORTH CENTRAL POWER STUDY AREA
Figure B-1.1

TABLE B-1.2

STRIPPABLE COAL SITES FOR 1000 OR MORE
BASE LOAD MINE MOUTH GENERATING PLANTS

DEPOSIT CHARACTERISTICS

Site Identification Number	Overburden in feet Min.	Max.	Coal thickness in feet - range	Reserves-in millions of tons	Heat Content Btu/lb.	Sulfur Content in percent
1	10	130	10 - 40	1,372	5,800-6,400	0.6-1.6
2	15	100	5 - 22	877	6,750-7,050	0.5-0.9
3	20	100	5 - 18	800	6,280	1.0
4	15	90	5 - 22	253	7,000-7,050	0.9
5	10	100	5 - 10	300	6,000	1.0
6	10	200	18 - 36	1,900	7,850	0.4
7	15	120	12 - 35	2,892	8,700	0.3
8	20	120	5 - 40	1,204	6,050	0.9
9	20	150	11 - 29	1,440	9,050	0.7
10	15	120	8 - 16	1,190	7,500-7,700	0.2-1.0
11	10	200	20 - 89	1,189	9,720	0.4
12	10	150	20 - 60	1,044	8,740	0.2
13	15	120	8 - 21	1,366	7,400-7,650	0.4-0.6
14	20	100	6 - 30	1,497	8,100-8,900	0.2-0.7
15	15	120	5 - 26	737	7,550	0.2
16	15	120	10 - 43	225	6,900	0.5
17	20	100	7	246	6,600	0.4
18	20	125	5 - 8	331	6,750-6,800	0.2
19	15	120	5 - 9	561	7,150	0.9
20	10	100	5 - 9	345	7,400	0.3
21	15	125	25	600	5,830	0.4
22	20	120	58	441	7,700	0.2
23	20	120	18	200	8,850	0.6
24	15	120	20	220	8,500	0.4
25	10	150	20	206	7,650	0.2
26	20	150	5 - 13	250	8,200	1.1
27	25	200	50 - 250	2,000	7,950	0.7
28 to 37	10	200	25 - 150	19,000	8,200-8,500	0.4-0.9
38	10	120	6 - 18	733	8,000-8,700	1.8-5.4
39	20	1,600	10 - 90	1,000	10,400	0.6
40	15	120	10 - 12	716	7,800	--
41	20	200	15 - 30	250	9,700	0.8
42	20	140	10 - 50	600	5,500	--

STRIPPABLE COAL SITES FOR 1000 MW OR MORE BASE LOAD MINE MOUTH GENERATING PLANTS[1]

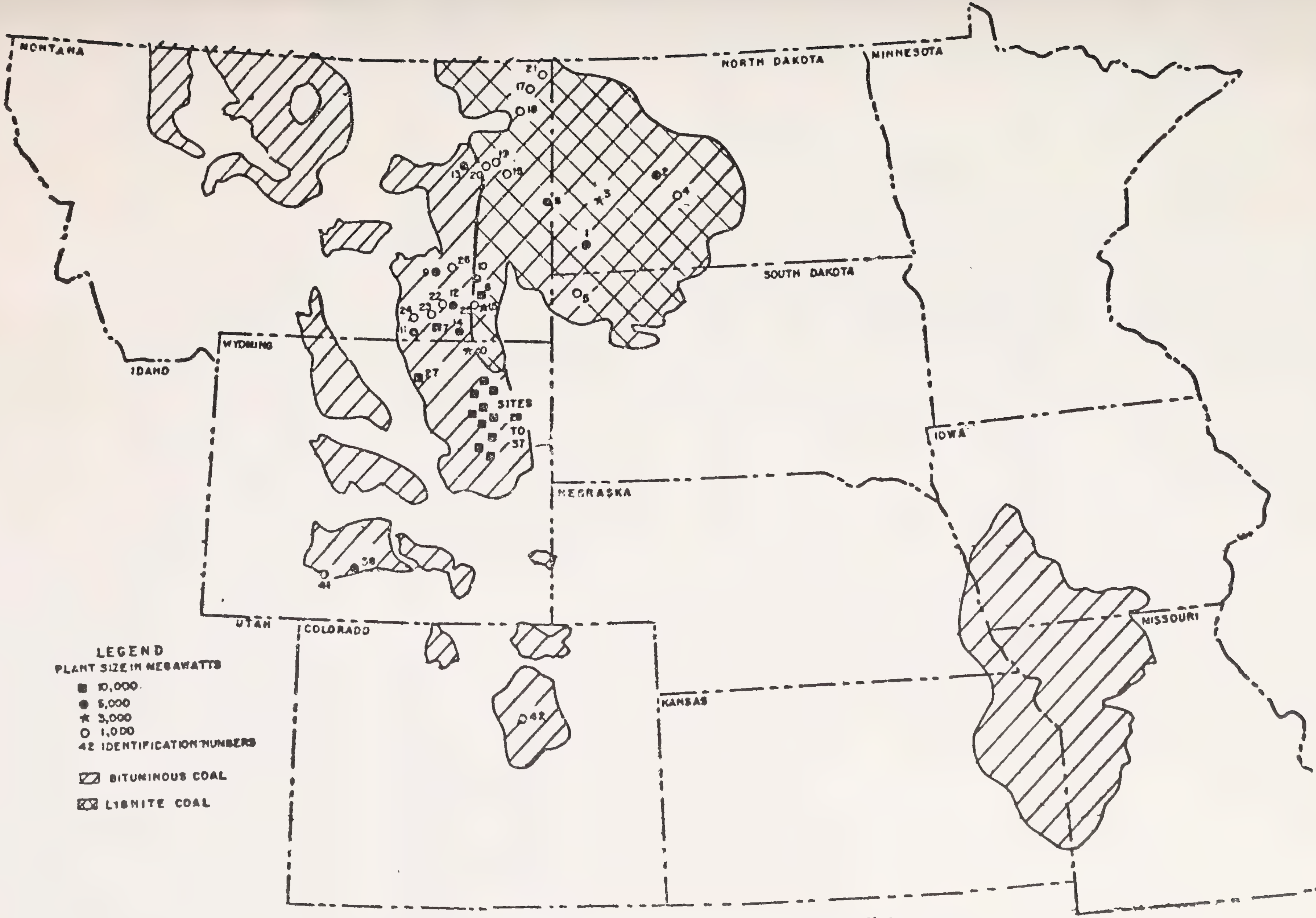
Site Identification Number	State	Plant Size MW	Deposit Name	Location
1	North Dakota	5,000	Slope & Bowman Counties	Bowman, N.D.
2	" "	5,000	Knife River	Beulah, N.D.
3	" "	3,000	Heart-River	Dickenson, N.D.
4	" "	1,000	Center	Center, N.D.
5	South Dakota	1,000	Cave Hills	Ludlow, S.D.
6	Montana[2]	10,000	Pumpkin Creek	20 m. N.W. Broadus, Mont.
7	"	10,000	Hanging Woman Creek	10 m. S. Birney, Mont.
8	"	5,000	Beach-Wibaux	Wibaux, Montana
9	"	5,000	Colstrip	Colstrip, Montana
10	"	5,000	Foster Creek	Volborg, Montana
11	"	5,000	Decker	Decker, Montana
12	"	5,000	Otter Creek	10 m. S.E. Ashland, Mont.
13	"	5,000	"S" Bed	10 m. N.W. Brockway, Mont
14	"	5,000	Moorhead	Moorhead, Montana
15	"	3,000	Broadus	Broadus, Montana
16	"	1,000	North Fork of 13 Mile Cr.	25 m. N.W. Savage, Mont.
[illegible]	"	1,000	Reserve	Reserve, Montana
	"	1,000	Fort Kipp	Fort Kipp, Montana
19	"	1,000	Lane	Ricney, Montana
20	"	1,000	Carroll	Paxton, Montana
21	"	1,000	Coalridge	Coalridge, Montana
22	"	1,000	Poker Jim - Lookout	Birney, Montana
23	"	1,000	Birney	Birney, Montana
24	"	1,000	Kirby	Kirby, Montana
25	"	1,000	Sonnette	Sonnette, Montana
26	"	1,000	Sweeney Creek	10 m. N.W. Brandenberg,
27	Wyoming	10,000	Lake De Smet	10 m. N. Buffalo, Wyoming
28	"	10,000	Gillette	15 miles N. of Gillette to Antelope Creek (55 miles S. of Gillette, Wyoming)
29	"	10,000		
30	"	10,000		
31	"	10,000		
32	"	10,000		
33	"	10,000		
34	"	10,000		
35	"	10,000		
36	"	10,000		
37	"	10,000		
38	"	5,000	Red Desert-Cherokee	N. of Wamsutter, Wyoming
39	"	5,000	Adaville	6 m. W. of Kemmerer, Wyo
40	"	3,000	Spotted Horse	Spotted Horse
[illegible]	"	1,000	Jim Bridger	25 m. N.E. Rock Springs,

Site Identification Number	State	Plant Size MW	Deposit Name	Location
42	Colorado[3]	1,000	Denver Basin	Watkins, Colorado
	Kansas Iowa Nebraska Missouri Minnesota		No sites	

[1]Based on: 1. 80% recovery
2. 9400 Heat Rate.
3. 35-year life at 85% plant capacity factor.

[2]In addition, Montana has other probable, but not yet identifiable, sites on Northern Cheyenne and Crow Indian Reservations.

[3]The Colorado site because of the very low Btu, high ash coal is only marginally ~~possible~~ attractive



LOCATION AND POWER GENERATION POTENTIAL OF
STRIPPABLE COAL DEPOSITS IN NORTH CENTRAL POWER STUDY AREA
Figure B-1.3

COAL COST AT MINE MOUTH

Field Identification Nos.	1970 Mine Mouth Cost ¢/Million Btu's
1-3	12.5-14
4-5	13 - 15
6-15	11 - 13
16-27	12 - 14
28-37	11 - 12
38-41	15 - 18
42	15 - 20

Coalfields with significant single or multiple beds in the coal measures mostly occupy broad structural basins and mostly are confined stratigraphically to the latest Cretaceous, and the immediately overlying early Tertiary strata. Stripping-coal reserves essentially must lie in areas of shallow, easily removable overburden usually near coalbed outcrops on eroded terrain. These outcrops and more or less of the adjacent coal downdip have burned at many deposits leaving topographic expressions of the erosion resistant clinker. Rank of the coal generally increases with geologic age, and up-slope approaching mountain areas with more intensive structural disturbances and attendant metamorphism. Sulfur content also increases accordingly in some metamorphic areas.

Northern Great Plains

All known strippable coal in North Dakota and South Dakota, and in the eastern parts of Montana, Wyoming, and Colorado are physiographically in the Northern Great Plains coal province. Nebraska and eastern New Mexico, also western states on the plains but with no known significant coal deposits, are excluded.

The Great Plains coal province also has identity geologically in that it largely is relatively flat-lying, featureless, undisturbed sedimentary rocks with almost all the significant coal measures enveloped in the latest Upper Cretaceous strata and the immediately over-lying early Tertiary formations.

The greatest coal resources of the Nation occupy broad, gentle, structural basins in this Great Plains province. The largest, the Williston Basin, extends from central North Dakota westward nearly 300 miles to include eastern Montana and from Canada southward into the corners of Wyoming and South Dakota on the northmost flanks of the Black Hills Uplift. Lignite and subbituminous coal of this vast Williston Basin constitute the greatest coal resource, and also by far the greatest stripping-lignite resource of the Nation.

Due to the old-age stage of physiography in the Northern Great Plains of the Williston Basin region, erosion has not severely dissected the relatively flat coal beds except in major river valleys and drainage channels, but nevertheless has reduced the overburden thicknesses in broad areas. Computing of commercial stripping reserves of coal in remarkably large areas therefore was permitted because of unusually favorable stripping-ratios and easily minable overburden strata. Added advantages of relatively low strip-mining costs, favorable ratios of costs in terms of effective Btu content of the coal, availability of water and facilities for mine-mouth power-plants and/or low transportation costs to eastern energy-fuel markets, and low sulfur contents are expected to encourage more large mining developments on strippable coal in North Dakota and Montana.

Some uraniferous lignites, generally lower in rank and higher in sulfur, molybdenum, and other trace elements, in southwestern North Dakota and northwestern South Dakota, however, may continue to be mined more profitably for uranium recovery during favorable marketing periods for nuclear-fuel sources. Thus, appropriate deletions in the computed commercial stripping-coal reserves were estimated for coal beds not suitable or available for energy fuel for the conventional electric utilities.

Adjacent and southwest of the Williston Basin, subbituminous coal in the great Powder River Basin of Montana and northcentral Wyoming is the largest resource of stripping-coal in the Nation. Erosion has more or less removed coal measures on the structural highs and beveled coalbeds in some places on the flanks of the Basin. Dips generally are steeper on the western flank approaching the Rocky Mountain Uplift. Very large stripping-coal reserves in areas of near-surface coal on flanks of the Powder River Basin in general have the advantages of unusually thick multiple coalbeds, a choice of stripping ratios low mining costs in terms of content, and sulfur contents averaging almost as low as the Williston Basin lignites.

The Denver Basin in the northwestern quadrant of Colorado is the third largest coal resource in the Great Plains province of the Western States with an estimated 4 billion tons of subbituminous coal (lignitic on the eastern, near-surface edges) in 6 counties. Due to steep dips flanking the Front Range of the Rocky Mountains, excessive depths to the coal beds in the anticlinal Boulder-Weld County underground mining field, low-rank of the near surface, lenticular, lignitic resources east of Denver, and the small size of stripping-coal reserve blocks in the Colorado Springs coal field, no commercial stripping-coal reserves suitable and available for the energy-fuel market were computed for the Denver Basin.

Rocky Mountains

All known strippable coal deposits in the rugged high central zones in Colorado and Wyoming are in the Rocky Mountain coal province. Numerous coal deposits in this province in New Mexico and Montana do not appear to offer significant commercial reserves of stripping-coal for the forseeable future.

STRIPPABLE COAL RESERVES OF NORTH DAKOTA

Location, Tonnage, and Characteristics of Coal and Overburden

by

Benjamin C. Pollard,[1/] Joseph Blake Smith,[1/] and Clinton C. Knox[1/]

ABSTRACT

The location and production potential of large blocks of strippable coal reserves in North Dakota were determined by using published data as a base and adding new drill hole data or other data contributed by companies owning or leasing coal lands. Deposits in 16 large blocks in North Dakota contain an estimated 4.1 billion tons of strippable lignite. All such coal is in the Fort Union Formation of western North Dakota and is lignite in rank.

Only lignite beds exceeding 5 feet in thickness, under less than 120 feet of overburden, and in large blocks of 5 million tons or more were included in the estimates. North Dakota, containing an estimated total 350 billion tons of lignite, ranks first in the nation in lignite resources (7).[2/] North Dakota lignite strip mining, increasing irregularly since it began in 1884, was at a record high of 4.7 million tons in 1969.

INTRODUCTION

This report is the third of a series on strippable coal (lignite) deposits in the Upper Missouri River basin. The previous two are on Montana (4) and Wyoming.[3/] The purpose of the series is to define the location, extent, and characteristics of the major strippable reserves and overburden in each State.

1/ Mining engineer, Intermountain Field Operation Center, Bureau of Mines, U.S. Department of the Interior, Denver, Colo.

2/ Underlined numbers in parentheses refer to selected references at the end of this report.

3/ Smith, Joseph Blake, Maynard F. Ayler, Clinton C. Knox, and Benjamin C. Pollard. Strippable Coal Reserves of Wyoming - Location, Tonnage, and Characteristics of Coal and Overburden. BuMines Prelim. Rept. 181, December 1970, 44 pp.

Several factors recently have stimulated interest in acquisition and development of coal reserves. One important factor is the increasing need for electric power. Major power markets are expected to develop, perhaps through extra-high-voltage interties with more populous regions and will require substantial additions to thermal power generating capacities. Another factor stimulating interest in the large strippable blocks of low-cost coal and lignite is the impending development of economic processes for the conversion of solid fuels to liquid and gaseous hydrocarbon fuels.

All published information on lignite occurrences in North Dakota was analyzed. All accessible data were collected from firms and individuals engaged in exploration and acquisition of coal lands in North Dakota. Outcrop and resource data in reports and files of the U.S. Geological Survey, U.S. Bureau of Land Management, and State agencies were also used in defining potential stripping areas. The strippable reserves in 16 areas are listed in table 1, and their locations are shown in figure 1.

TABLE 1. - Strippable lignite reserves of North Dakota

Deposit	Location on fig. 1	Strippable reserves, millions of short tons	Maximum overburden, thickness ft
Noonan-Kincaid .	1	15	50
Niobe	2	146	100
Avoca	3	380	75
M & M	4	100	120
Velva	5	5	50
Washburn	6	30	50
Wilton	7	15	50
Renner's Cove ..	8	78	50
Hazen	9	71	50
Beulah-Zap	10	380	120
Stanton	11	21	50
Center	12	253	50
Dunn Center	13	29	50
Dickinson	14	798	100
Beach	15	450	120
Bowman-Gascoyne	16	1,372	120
Total	-	4,143	-

Analysis, percent					Btu per lb
Moisture	Volatile	Fixed C	Ash	Sulfur	
43.8	24.1	25.2	6.9	.9	5,960

In addition to Bowman and Gascoyne, four outlying deposits in Slope County are estimated to contain a strippable reserve of 660 million tons (15). These deposits, as reported in the literature, are described as "possible deposits of strippable lignite." Owing to the scarcity of data, the reserve tonnage has not been included in this report.

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ABSTRACT

Coal resource data from published sources and company files were used by the Bureau of Mines to determine the location and extent of strippable coal reserves in Wyoming. Total strippable reserves of 23 billion tons were estimated in 7 major coal areas. Seven large strip mining operations were active in 1969, and their production totaled 4½ million tons of coal. Cutoffs used to define strippable reserves were (1) minimum coalbed thicknesses of 5 feet; (2) overburden-to-coal ratios of less than 10 cubic yards of overburden per ton of coal; and (3) total overburden thicknesses of less than 120 feet, except where reserves occur in multiple beds or a single thick bed.

Tertiary rocks along margins of the Powder River basin contain most of the strippable coal reserves in Wyoming. The Wyodak beds, ranging in combined thickness from 30 to 130 feet, crop out on the east flank of the basin and contain an estimated 19 billion tons of strippable subbituminous C-rank coals under less than 200 feet of overburden. Partings between these beds total less than 60 feet. The 100- to 200-foot-thick Healy bed on the western flank of the basin and the 35-foot-thick School and 20-foot-thick Badger beds on the south also contain large strippable reserves. Elsewhere in Wyoming, strippable deposits are subbituminous coal of Late Cretaceous and Tertiary ages, mostly in the Hanna and Great Divide basins in the south-central portion of the State and in the Kemmerer-Hamms Fork region in the southwestern corner.

INTRODUCTION

This report is the second of three concerning strippable coal deposits of States in the upper Missouri River basin. The first in the series was on strippable coal reserves of Montana (3).[2/] The purpose of the trilogy is to define the location, extent, and characteristics of the major strippable coal deposits in Montana, Wyoming, and North Dakota (26).

Wyoming has the largest coal resources of any State--546 billion tons within 6,000 feet of the surface (2). Interest in large strippable coal reserves has been stimulated recently by accelerating electric power demands, significant additions to thermal power generating capacity, and prospects for development of synthetic fuels from coal.

Projected shortages of natural gas reserves and research progress on commercial processes for converting coal to liquid and gaseous hydrocarbon fuels have enlisted further competitive interest by petroleum and coal companies in the search for large blocks of low-cost coal.

2/ Underlined numbers in parentheses refer to items in the list of references at the end of this report.

A commercial-scale conversion plant producing liquid products would be expected to use a minimum of 10 million tons of subbituminous C-rank coal per year, and one producing gaseous products would use a minimum of 6.5 million tons of such coal annually. When economic and technologic factors justify their construction, such plants likely would be fueled by some of the largest and most technologically advanced strip coal mines in the world. Moreover, each such plant is expected to require strippable reserves of at least 200 million tons.

This report summarizes and interprets information available to the Bureau of Mines on strippable coal in Wyoming. Firms and individuals engaged in exploration and acquisition of coal lands in Wyoming were consulted to obtain supplemental information. Coal outcrop and reserve data in reports of the U.S. Geological Survey were used freely. Cursory examinations were made of the coalfields and strip coal mines, and factors that would affect strip mining, particularly coal and overburden characteristics, were noted.

Where drill hole data for defining stripping limits or adequate topographic maps were not available, strippable deposits were defined by using the stratigraphic interval between the coalbed of interest and an overlying coalbed, together with maps showing surface traces of coalbed outcrops to locate stripping limits.

Most of the strippable reserves of Wyoming are in strata of Tertiary age on margins of the Powder River basin. This area also contains more than 78 percent (95 billion tons) of Wyoming's 121.5-billion-ton reserve of mapped and measured coal that lies within 3,000 feet of the surface (2, 4).

Strippable coal deposits and coalfields having strip mining potential are shown on figure 1 and listed in table 1.

Location 21: Wind River Basin Coalfields (38)

Coal of the Mesaverde and Fort Union Formations is found in five fields in the Wind River basin. These coalfields are as follows:

Muddy Creek field, Tps 5-6 N, R 3 E to R 3 W.
Pilot Butte field, T 3 N, R 1 W.
Hudson field, Tps 1-2 S, R 2 E.
Alkali Butte field, T 2 S, R 6 E, and T 34 N, Rs 94-95 W.
Powder River field, T 31-33 N, R 85-87 W.

All have coalbeds 6 feet or more thick, although only the Alkali Butte field seems to have continuity in the thicker beds. In all other cases, the measured sections indicate considerable thickening and thinning of the beds.

It is doubtful that strip mines of any consequence can be developed in any of these areas because of generally steep structural dips. The Alkali Butte field, the most favorable from the coal thickness standpoint, is located around the plunging nose of an anticline. Dip of the beds varies from 12° to 54°. Average dip is about 20°. This dip, combined with a maximum relief of 500 feet in the area, precludes the possibility of strip mining along the flank of a favorably located hill. At best the tonnage that could be developed would be quite low.

Within the other areas having thicker coalbeds, the formations dip from 10° to overturned.

Although these coals undoubtedly could be mined, many other areas in Wyoming warrant prior consideration.

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ABSTRACT

An investigation was made to determine the location and extent of large blocks of strippable coal in Montana. By using published reserve data as a base and adding drill hole data contributed by companies owning or leasing coal lands, 37 deposits containing 12.7 billion tons of strippable coal were delineated. All strippable deposits are in the Fort Union region of eastern Montana.

Only beds 5 or more feet thick were included in estimates of strippable reserves; most of the beds are under less than 120 feet of overburden, and all are under less than 200 feet.

INTRODUCTION

This report is the first of a series on strippable coal deposits in Montana, Wyoming, and North Dakota. The purpose of the series is to define the location, extent, and other characteristics of the major strippable coal deposits in each of these States.

Several factors recently have stimulated interest in the development of coal resources in Montana, particularly the substantial strippable reserves in the eastern portion of the State. One important factor is the increasing need for electric power. Several additions to the thermal-electric generating capacity of Montana are planned or are under construction. If major power markets can be developed, perhaps through extra-high-voltage interties with more populous regions, such as the Pacific Northwest, then substantial additions ultimately will be made to thermal power generating capacity in or near the Montana coalfields. Another factor stimulating interest in large blocks of low-cost coal is the impending development of processes for the economic conversion of coal to liquid and gaseous hydrocarbon fuels. A 100,000-bpd conversion plant producing liquid products at a conversion efficiency of 60 percent would require a Btu input equivalent to 18 million tons of subbituminous C coal per year, and one of the same efficiency producing 250 million cu ft of gaseous products per day would require at least 7.5 million tons of the same rank coal per year. Strip mines serving such plants would be among the largest coal mines in the world, requiring strippable coal reserves of 200 million tons or more.

All published information on coal occurrences in Montana was analyzed. Firms and individuals engaged in exploration and acquisition of coal lands in Montana were consulted to obtain supplemental information. Coal outcrop and reserve data in reports of the U.S. Geological Survey were incorporated when available.

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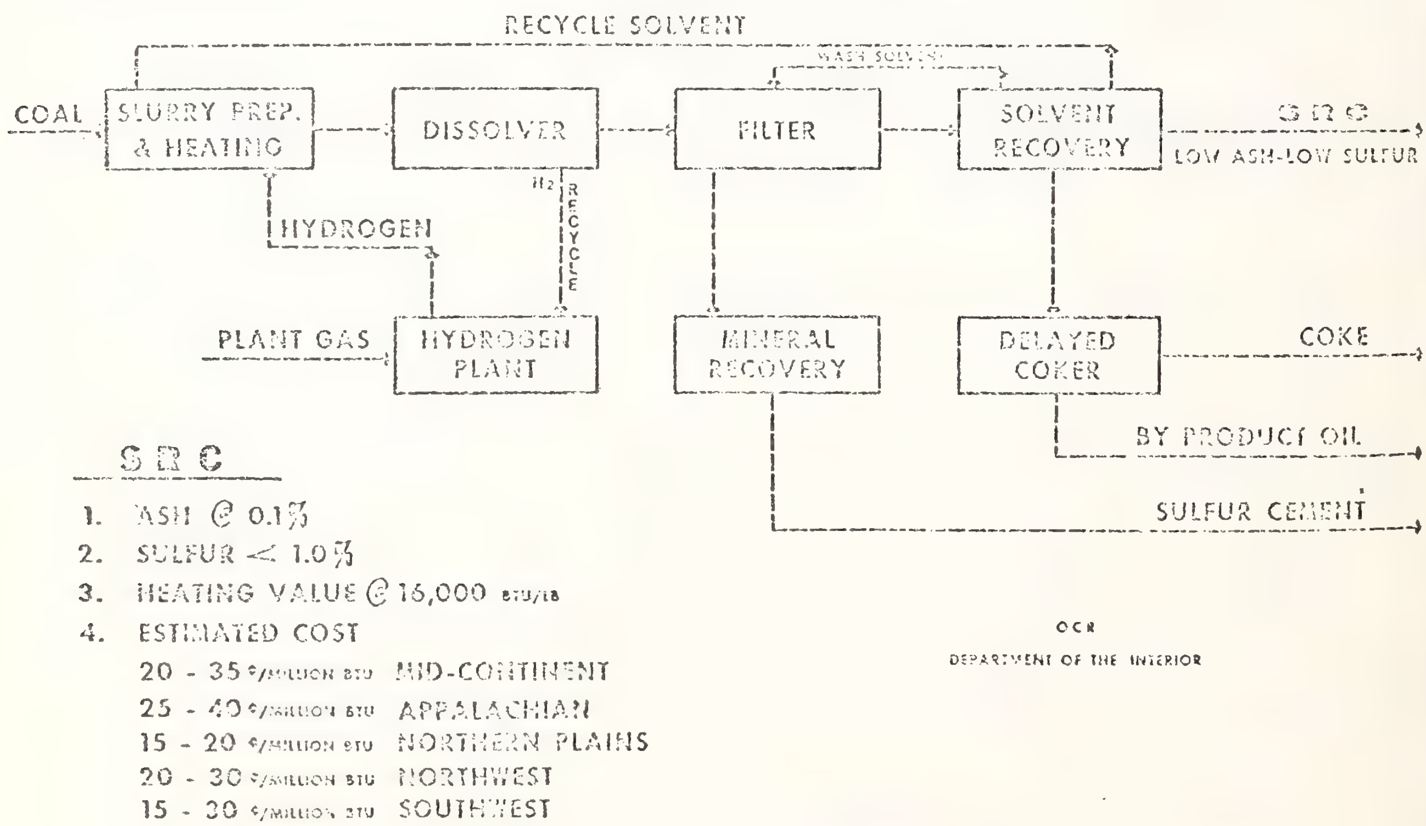
Solvent Refined Coal (October 10, 1966-October 10, 1971) — The Pittsburg & Midway Coal Mining Co. — $7,640,000

Research work on the solvent refined coal process was undertaken in August 1962 by the Spencer Chemical Corporation, Merriam, Kansas, and was completed in February 1965. A new contract was signed with an affiliated company in 1966 to design, construct and operate a 75-tons-per-day pilot plant to establish commercial feasibility of the successful laboratory work.

Solvent refined coal is produced by first dissolving coal under pressure with a small quantity of hydrogen to produce a liquid product containing approximately 90 percent of the carbon in the original coal feed. After solvation, the dissolved coal is filtered to remove virtually all of the ash and sulfur. A small quantity of light liquid product with a high content of butane, toluene and xylene is distilled off, and the carbon, together with about 20 to 40 percent volatile matter, is solidified. The ash content is reduced to approximately one-tenth of 1 percent, and sulfur is reduced to approximately 1 percent or less.

Solvent refined coal is a quality-controlled

Solvent Refined Coal



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product with a heating value of approximately 16,000 B.t.u.'s per pound from any bituminous or lower grade coal feedstock. If the volatile matter is left with the carbon, the material can be liquefied at about 350° F. and used as a boiler fuel. It can be used also as a solid fuel, but it is expected that development of special nozzles and injection equipment will be required. This material may be treated further in a coker to drive off the volatile matter thus producing either metallurgical coke or electrode carbon. Solvent refined coal is believed to be one of the most economical and advanced processes that can be developed to produce electric power from high-sulfur coal with minimal air pollution. The byproduct oils which are distilled off may be recovered along with elemental sulfur to provide manufacturing credits.

This solvent refined coal product can also be used as a feedstock for hydrogenation to produce synthetic petroleum. The estimated costs of producing solvent refined coal have been detailed in a comprehensive estimate prepared for The Pittsburg & Midway Coal Mining Co. by Stearns-Roger Corporation (OCR R & D Report No. 53).

The estimates are for three geographic areas within the United States, and the required selling price of mine-mouth solvent refined coal ranges from 19 to 41 cents per million B.t.u.'s depending on credit for the amount of coke or carbon prepared for metallurigical or electrical uses. Minor price modifications result from input coal costs and additional byproduct credits.

Intermediate Coal Hydrogenation Process, (October 2, 1969-October 1, 1974) — University of Utah — $834,000 U.S. Government Funds; $176,340 State of Utah Funds

Research on a process for using Western U.S. coals in direct, one-step hydrogenation to produce synthetic crude oil, solid char fuel and fuel gases is the main objective of this Office of Coal Research project. Hydrogenation occurs when finely ground coal passes briefly (0.05-0.5 seconds) through a heated pressurized zone in free fall and dilute phase.

It is contemplated that this process, already demonstrated on a bench scale in a 2-pound semicontinuous apparatus will be expanded to a continuous unit capable of handling 50 pounds of coal per hour. Typical conversions obtained are 70 to 85 percent with 45 to 55 percent of the coal converted to liquids and 20 to 30 percent to gases.

The real significance of the project is the demonstration that coal hydrogenation reactions in this process are very rapid and, therefore, large quantities of coal can be processed in a very small reactor. This is a tangible advantage over all current processes using a liquid slurry of coal and vehicle solvent.

Research on coal hydrogenation is supplemented by further work being done on the processing of coal oils. Work on the hydrocracking process to produce salable products from the liquids produced by coal hydrogenation is being performed. Reactor systems are being studied as well as the development of a suitable catalyst with the right type of activity and selectivity for coal oils.

Catalyst systems are also being studied to minimize costs and maximize catalyst recovery. The most promising catalysts studied so far are recovered by water extraction. These can be recycled with very little loss of activity. These research projects also involve the analysis and characterization of products.

Research has been and is being done on solvent extraction, pyrolysis, carbonization, hydrogenation, and microwave radiation of coal where the studies are directly related to the production of liquids, gases and char by intermediate pressure hydrogenation.

The very short residence times used in the hydrogenation process suggest that more work needs to be done to determine the mechanisms, rate determining steps, etc., for the several types of reactions that are possible under the operating conditions.

Currently the coals being studied include those from Utah, Wyoming, Colorado, Arizona, Montana, and Illinois. Coal ranks from low-volatile bituminous to lignite coals have been processed. Data have been obtained on coals from commercially operated mines and from areas of the West as yet undeveloped.

EXCERPTS FROM OCR REPORT ON ASHLESS LOW-SULFUR FUEL FROM COAL

ECONOMIC EVALUATION OF A PROCESS TO PRODUCE ASHLESS LOW-SULFUR FUEL FROM COAL

I. SUMMARY

A general economic evaluation has been made of the Pittsburg & Midway process for producing an ashless, low-sulfur fuel from coal. The evaluation was based on a 10,000 ton per day de-ashing plant located at a mine-mouth power plant in the Ohio-Illinois-Kentucky area. The conceptual design of the de-ashing plant, together with investment and operating costs, were developed through a subcontract with Stearns-Roger Corporation. Investment and operating costs for the coal mine, plus the value of the by-products from the plant, were estimated by Pittsburg & Midway. This economic information was then used by P&M to determine the required selling price of the de-ashed coal product. The selling price was calculated on the basis of a 10% rate of return on investment by the discounted cash flow method, using the sum-of-years-digits method for depreciation over a 20-year period.

Three different process schemes were evaluated. These were:

Case 1 - use of all the de-ashed coal product as fuel;

Case 2 - coking of 10% of the de-ashed coal product to produce electrode carbon and use of the remaining de-ashed coal product as fuel;

Case 3 - similar to Case 2, but coking of 25% of the de-ashed coal product.

The required selling price of the de-ashed coal product delivered as a liquid directly to an adjacent power plant for each of the above three cases is as follows:

Case 1 - 29.5¢ per MM BTU

Case 2 - 27.7¢ per MM BTU

Case 3 - 19.5¢ per MM BTU

The required selling price of the de-ashed coal product in solid form at the de-ashing plant for each of these cases is as follows:

Case 1 - 31.6¢ per MM BTU

Case 2 - 29.9¢ per MM BTU

Case 3 - 22.1¢ per MM BTU

-1-

These figures show that the addition of a coking unit to make electrode coke from a portion of the de-ashed coal product is economically attractive, and results in a significant decrease in the required selling price of the de-ashed coal product as an industrial fuel. The economic study has also revealed that by-product credits are very important in determining the required selling price of the de-ashed coal product. It is believed that reasonable values for by-products have been used throughout the study.

The use of de-ashed coal product in new power plants will result in lower operating and investment costs than for plants burning raw coal. For example, the savings for an 800 MW power plant have been estimated to be equivalent to 4.3¢ per million BTU. This decreases the effective price of the liquid de-ashed coal product from 29.5¢ per MM BTU to about 25.2¢ per MM BTU for purposes of comparison with raw coal. For the solid fuel, the savings at a new power plant are only 3.3¢ per MM BTU. The net effective price of the solid de-ashed product is thus reduced from 31.6¢ to 28.3¢ per MM BTU.

Since the product is very low in sulfur, it will be a suitable fuel for areas where there are severe restrictions on the discharge of sulfur dioxide to the atmosphere. The cost of alternate methods of sulfur removal then represents an additional credit for de-ashed coal in comparison with either raw coal or residual petroleum fuel. Although their magnitude is uncertain at this time, these additional credits should make the effective price of the de-ashed coal considerably lower than actually calculated. Even without credit for low sulfur, the price of 29-32¢ per MM BTU is less than that for residual petroleum fuel in many areas. In general, it appears that the de-ashed coal product will be an attractive fuel for power plants and other industrial uses in areas having restrictions on atmospheric pollution by sulfur dioxide.

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III. DISCUSSION

A. General

To provide a basis for the economic evaluation, Stearns-Roger Corporation of Denver, Colorado were requested to develop a conceptual design for a 10,000 ton per day commercial coal de-ashing plant and to estimate in some detail the investment and operating costs for the plant. The report of Stearns-Roger covering the conceptual design of a 10,000 ton per day commercial plant is included as Appendix A to this report. A general description of the process, together with assumptions used, is included in Appendix A.

To complement the information supplied by Stearns-Roger, the operating and investment costs for mining the coal, plus the value of the by-products, were determined by P&M. This information was then combined by P&M into an economic evaluation of the overall process. The economic evaluation of the process, including both mine and processing plant, is discussed in the following sections.

Three different process schemes were evaluated in this study. These were:

Case 1 - use of all the de-ashed product as fuel;

Case 2 - coking of 10% of the de-ashed product to produce electrode carbon and use of the remainder of the de-ashed coal product as fuel;

Case 3 - similar to Case 2, but coking of 25% of the de-ashed coal product.

The two coking levels were arbitrarily selected to allow evaluation of two different coke production rates.

B. Coal Mining Costs

The Stearns-Roger conceptual design was based on a mine-mouth processing plant located in the Ohio-Illinois-Kentucky area. Investment and operating costs for a typical deep mine in this area to supply 10,000 tons per day of coal have been estimated by P&M. A summary of the costs for the mine, including a coal cleaning plant, is given in Table I. These operating costs do not include the cost of power, since the necessary power (5700 KW) is supplied by the coal processing plant.

C. Processing Plant Costs

1. General

The Stearns-Roger conceptual plant design was for a coal charge rate of 10,000 tons per stream day. The plant was assumed to operate for 8,000

TABLE I

COAL MINING COSTS

Basis: 10,000 Ton Per Day Deep Mine located in Ohio-Illinois-Kentucky area.

INVESTMENT	
Mining Equipment	$ 5,000,000
General Underground:	
(1) Coal conveyors	4,300,000
(2) Power distribution	2,500,000
(3) Supply & materials handling & personnel transportation	1,500,000
Slope Development	1,595,000
Coal Cleaning Plant	2,400,000
Coal Storage & Handling	1,300,000
Shop & General Surface Facilities	1,000,000
Contingencies at 10%	1,960,000
SUBTOTAL	$21,555,000
Land	2,000,000
TOTAL	$23,555,000
ANNUAL OPERATING COSTS	
Labor	$ 3,660,000
Supervision	600,000
Materials	3,500,000
Power*	--
Welfare Fund & Vacation Pay	1,667,000
Payroll Taxes & Company Insurance	366,000
General Taxes & Insurance	100,000
Miscellaneous	167,000
TOTAL	$10,060,000

*Supplied from By-product Power (5700 KW)

TABLE II

ANNUAL OPERATING COSTS

	Without Coking	With 10% Coking	With 25% Coking
Operating Labor (139/154/158 Men at $4.00/Hr.)	$1,156,500	$1,281,300	$1,314,600
Maintenance Labor	1,009,500	1,134,600	1,241,100
Maintenance Material	1,514,300	1,701,900	1,861,700
Supervision and Technical Service (15% of Labor)	324,900	362,400	383,400
Indirect Labor (15% of Labor)	324,900	362,400	383,400
Payroll Overhead (45% of Payroll)	1,267,100	1,413,300	1,495,100
Property Tax and Insurance (15% of Investment)	1,070,700	1,194,500	1,299,700
Fuel Gas: 1548/1480/1378 MM BTU/Hr. at 26.9¢/MM BTU	3,331,300	3.185,000	2,965,500
Water (2900 GPM at 10¢/1000 Gal.)	139,200	139,200	139,200
Catalyst, Chemicals, etc.	244,200	244,200	244,200
Interest on Working Capital ($5,000,000 at 7.5%)	375,000	375,000	375,000
TOTAL	$10,757,600	$11,393,800	$11,702,900

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hours per year, equivalent to an operating factor of 91.3%. On a calendar day basis, the average coal charge rate would be 9,130 tons per day. All of the figures used in this and the Stearns-Roger report (Appendix A) are on a stream day basis, i.e. corresponding to a charge rate of 10,000 tons per day.

The original Stearns-Roger conceptual design was based on the assumption that the liquid de-ashed product would be solidified and shipped from the plant in solid form. When possible, however, it is generally advantageous to locate the de-ashing plant next to the power plant and pump hot liquid de-ashed product directly to the power plant for combustion in liquid form. This eliminates the product solidification and storage facilities in the de-ashing plant, as well as the solids handling and pulverizing equipment in the power plant. The current study emphasizes the situation where the de-ashed coal would be supplied to an adjacent power plant in liquid form.

2. Investment Costs

Elimination of the product solidification and storage facilities results in a decrease in investment costs for the de-ashing plant. If the de-ashed coal product is handled as a liquid, however, some provision must be made for stand-by storage of liquid fuel. Because of the high viscosity of the de-ashed coal product, it is more reasonable to store an emergency supply of filtered coal solution, i.e. the de-ashed coal before separation of process solvent. This material has a viscosity in the same range as No. 6 fuel oil, and would require about the same type of storage facilities. Storage for three days supply of fuel has been provided on the assumption that any additional fuel required during de-ashing plant shut-downs would be available from other sources on a daily basis.

The total investment costs for each of the three cases given in the Stearns-Roger conceptual design (Table 2 of Appendix A) have been modified to eliminate the product solidification and storage facilities and to add liquid storage facilities. The facilities required for solidification and storage of the de-ashed product would normally cost less for the two coking cases because the coker feed is not solidified. The investment costs allowed for these facilities in the Stearns-Roger report were the same in each of these cases, however, and for this reason, the amounts deducted are the same for each of the three cases. The revised investment costs are as follows:

	No Coking	10% Coking	25% Coking
Original Investment	$75,104,000	$83,355,000	$90,371,000
Deduct Product Solidification and Storage Facilities	- 3,873,000	- 3,873,000	- 3,873,000
NET	$71,231,000	$79,482,000	$86,498,000
Add Liquid Storage Facilities	+ 150,000	+ 150,000	150,000
Revised Investment	$71,381,000	$79,632,000	$86,648,000

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TABLE IV

PRODUCT YIELDS USED FOR ECONOMIC EVALUATION

Coal Charge: 10,000 Tons Per Day

Products: Tons/Day	Without Coking	With 10% Coking	With 25% Coking
De-ashed Coal	5,860*	5,125*	4,050*
Light Liquid	930	940	956
Sulfur	250	250	250
Phenol	36	36	36
Cresylic Acids	120	120	120
Carbon Dioxide	100	100	100
Coker Gas Oil	--	145	362
Coke	--	371.7	929.2
Binder Pitch	--	137.2	343

*15,900 BTU per pound, 1% Sulfur.

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TABLE V

BY-PRODUCT CREDITS (WITHOUT COKING)

By-Product	Quantity			Unit Price	Annual Total
	lbs./Hr.	Bbl./Day	Tons/Day		
Light Liquid	77,624	6,800	--	$3.50/Bbl.	$ 7,940,000
Sulfur	20,800	--	223.2*	$35/LT	2,600,000
Phenol	3,000	--	36	8¢/lb.	1,920,000
Cresylic Acids	10,000	--	120	4¢/lb.	3,200,000
Carbon Dioxide	8,330	--	100	$6.00/Ton	200,000
Electrical Power	26,690 KWH/Hr.			0.5¢/KWH	1,070,000
				TOTAL	$16,930,000

*Long Tons

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TABLE VI

BY-PRODUCT CREDITS (10% COKING)

By-Product	Quantity lbs./Hr.	Quantity Bbl./Day	Quantity Tons/Day	Unit Price	Annual Total
Light Liquid	78,471	6,860	--	$3.50/Bbl.	$ 8,000,000
Sulfur	20,800	--	223.2*	$35/LT	2,600,000
Phenol	3,000	--	36	8¢/lb.	1,920,000
Cresylic Acids	10,000	--	120	4¢/lb.	3,200,000
Carbon Dioxide	8,330	--	100	$6.00/Ton	200,000
Coker Gas Oil	12,068	827	--	$3.15/Bbl.	868,000
Coke	31,000	--	371.7	$25/Ton	3,100,000
Binder Pitch	11,420	--	137.2	$35/Ton	1,600,000
Electrical Power	24,910 KWH/Hr.			0.5¢/KWH	1,000,000
				TOTAL	$22,488,000

*Long Tons

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TABLE VII

BY-PRODUCT CREDITS (25% COKING)

By-Product	Quantity lbs./Hr.	Quantity Bbl./Day	Quantity Tons/Day	Unit Price	Annual Total
Light Liquid	79,741	6,990	--	$3.50/Bbl.	$ 8,150,000
Sulfur	20,800	--	223.2	$35/LT	2,600,000
Phenol	3,000	--	36	8¢/lb.	1,920,000
Cresylic Acids	10,000	--	120	4¢/lb.	3,200,000
Carbon Dioxide	8,330	--	100	$6.00/Ton	200,000
Coker Gas Oil	30,170	2,065	--	$3.15/Bbl.	2,170,000
Coke	77,400	--	929.2	$25/Ton	7,730,000
Binder Pitch	28,600	--	343	$35/Ton	4,000,000
Electrical Power	22,265 KWH/Hr.			0.5¢/KWH	891,000
				TOTAL	$30,861,000

*Long Tons

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EXCERPTS FROM OCR REPORT (CONTINUED)

TABLE X

EFFECT OF CHANGES IN COSTS OR BY-PRODUCT PRICES ON THE SELLING PRICE OF DE-ASHED COAL PRODUCT

A change in the item below by the amount specified.	Will change the selling price of de-ashed coal product by...(¢/MM BTU) Without Coking	With 10% Coking	With 25% Coking
1. Investment (includes investment-based items)			
$1.0 MM	0.41	0.47	0.59
2. Operating Cost Factors			
(a) Cost of Labor (includes overhead) $1.00 per hour	0.98	1.23	1.58
(b) Quantity of Labor (includes overhead) 10 men per shift	1.06	1.21	1.53
(c) Cost of Fuel Gas 10¢/MM BTU	2.00	2.18	2.56
3. By-Product Prices			
(a) Sulfur - $10/Ton	1.25	1.43	1.80
(b) CO_2 - $1.00/Ton	0.05	0.06	0.08
(c) Light Liquid - $1.00/Bbl.	3.65	4.20	5.33
(d) Phenol - 1¢/lb.	0.38	0.44	0.56
(e) Cresylic Acids - 1¢/lb.	1.29	1.47	1.86
(f) Power - 0.1¢/KWH	0.35	0.37	0.42
(g) Mineral Residue (Ash) - $1.00/Ton	0.39	0.44	0.56
(h) Coke - $5/Ton	--	1.14	3.61
(i) Coker Gas Oil - $1.00/Bbl.	--	0.51	1.60
(j) Binder Pitch - $5/Ton	--	0.42	1.33

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TABLE IX

ECONOMIC SUMMARY
(Liquid De-ashed Product)

		Without Coking	With 10% Coking	With 25% Coking
Investment Costs				
Mine		$23,555,000	$23,555,000	$23,555,000
Plant		71,381,000	79,632,000	86,648,000
	TOTAL	$94,936,000	$103,187,000	$110,203,000
Operating Costs				
Mine		$10,060,000	$10,060,000	$10,060,000
Plant		10,757,600	11,393,800	11,702,900
	TOTAL	$20,817,600	$21,453,800	$21,762,900
Cash Earnings Required for 10% DCF* Return		+14,400,000	+16,100,000	+17,500,000
	TOTAL	$35,217,600	$37,553,800	$39,262,900
By-product Credits		-16,930,000	-22,488,000	-30,861,000
Required Return from De-ashed Coal Product.		$18,2[illegible]0	$15,065,800	$ 8,401,900
Total De-ashed Coal Product Available				
Tons/year		1,950,000	1,709,300	[illegible],350,800
MM BTU/year		62,000,000	54,400,000	43,000,000
Required Selling Price of De-ashed Coal Product				
(¢/MM BTU)		29.5	27.7	19.5

*Includes Depreciation

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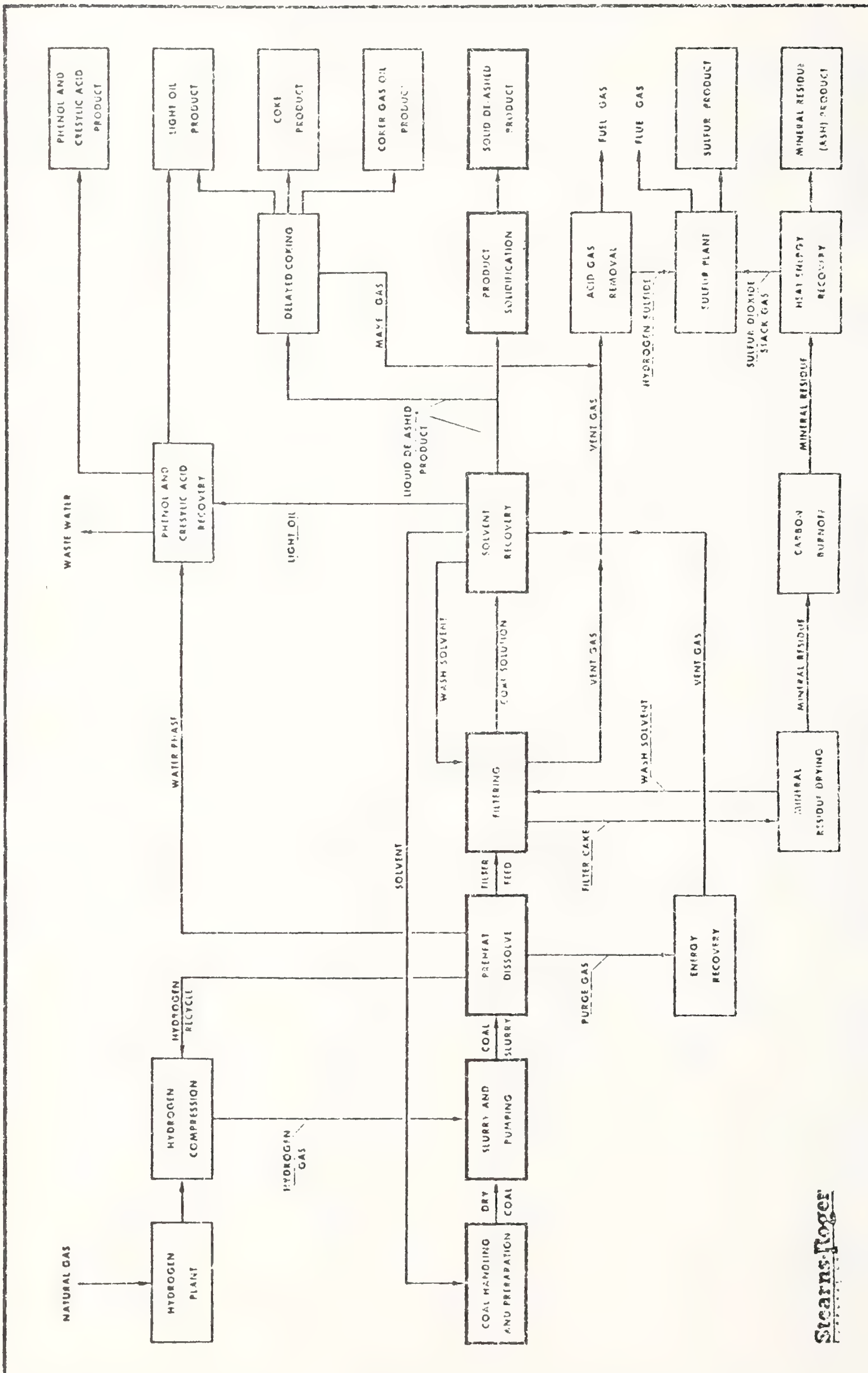

FIGURE 1. PROCESS DIAGRAM - CONCEPTUAL COAL DE-ASHING PLANT

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VII. HYDRO-GENERATION

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Summary and Conclusions

The primary purpose of the Hydro-Generation Task Force was to locate and compile data on potential hydropeaking sites (conventional, pure pumped-storage, and the combination of the two) in the North Central Power Study Area that could be integrated with the potential thermal generation. The investigation was subsequently limited to the main stem of the Missouri River and the Rocky Mountain area by the Steering Committee. It was the consensus of that committee that the potential hydropeaking sites in the various participating systems area would be considered in their alternate cost determination when comparing the NCPS costs for delivered power and energy.

Data on the potential hydropeaking sites in the specified area were compiled by the Task Force members. For a study of this magnitude it was felt that the sites should be limited to 100-mw and larger developments. Data on the 30 sites investigated are given on Exhibit A.

The Steering Committee directed the Task Force to investigate only hydropeaking developments with an 8-hour operation. To arrive at the pumping energy required for the pure pumped-storage installations it was assumed that 3 kwh would be required for every 2 kwh generation due to losses encountered in total operation. The cost of pumping energy required is included in the Economics Section of this report.

For Phase I of the NCPS the Steering Committee decided that the hydropeaking would be limited to 3000 mw on the East system to serve load factor power to small power users. Large power users would require base load power. From a standpoint of transmission system economics the most likely sites that could be integrated into the East system were the pumped-back Rockwood Cutler-Park (1760 mw) and Sheep Mountain (1240 mw) sites located near fossil fuel plants.

Hydropeaking

A. Conventional Hydropeaking Plants

In the study area there are a limited number of undeveloped conventional hydroplants. A conventional hydropeaking plant includes a reservoir to regulate the flows of the river. These flows are released through the turbines which drive the generators. A run of the river plant normally has limited storage space and operation is dependent upon the river flows. During high water the plant usually operates at full capacity whereas during low river flow conditions plant output is limited. Conventional hydroplants with large storage reservoirs offer more flexibility because they can be operated to meet a specified load curve. Plant operation is sometimes restricted by downstream water requirements; however, this problem can be overcome by the installation of an afterbay dam. The afterbay dam or reregulation dam constructed below the main powerplant enables varied releases at the powerplant with a regulated release from the lower dam.

B. Pumped-Storage Developments

Pure pumped-storage developments produce energy from water that has been previously pumped to an upper reservoir. Although pumped-storage projects may have conventional hydroelectric generating units and separate pumps, most developments utilize reversible pump-turbine units.

A pumped-storage plant has the same operating characteristics as a conventional hydroplant, e.g., rapid startup and loading, long life, low operating and maintenance costs, and low outage rates. The pumped-storage plant's ability to accept and reject large blocks of load quickly makes it more flexible than thermal plants in following the load fluctuations which occur on a minute-to-minute basis in an electric power system. This unique characteristic of a hydroplant to follow the changes in system load permits a more uniform and efficient loading of thermal units. Also by pumping the water back to the upper reservoir in the offpeak periods, the base load of the thermal units is improved. This reduces the severe cycling of the thermal units and improves their efficiency and durability.

A pumped-storage plant can also play an important role in assuring system reliability. With proper design the units can be operated for spinning reserve because the units can be loaded in a minimum time.

C. Combination Conventional-Pumped Storage Plants

These developments use both pumped water and natural runoff for generation. Sometimes these projects have conventional hydroelectric generating units and separate pumps depending upon hydrologic and site conditions.

D. Use in Serving the Load

A number of factors cause the variation in power demands on an electric system, e.g., living habits and work schedules of people served, characteristics of the industries included in the load, and weather extremes. System loads are highest during the normal working days and drop off during late evening and weekends. Thus, while about 50 percent of the typical system's capacity must operate almost continually, or at base load, the remainder of the capacity, which is utilized to serve the peaks of the load and provide reserve capacity, is idle for portions of time. Whether the peak demands of a system last for a few minutes or a few hours, generating capacity must be available to supply the demand at the moment it develops.

The base load portion of the load is normally supplied with the newest low-cost efficient thermal units. The older thermal units are normally operated at a lower plant factor. The peak portion of the load is ideally served by hydroplants and gas turbines. Due to the short supply of fuels for gas turbines, the pumped-storage plants will undoubtedly be depended upon more heavily in the years to come to serve the system peaks and provide spinning reserves.

Study Assumptions and Qualifications

The Hydro-Generation Task Force established various study assumptions and qualifications before work was initiated. Additional study assumptions and qualifications were introduced as the work progressed. This report is based on the following assumptions and qualifications:

(1) Minimum capacity of peaking plant to be considered would be 100 mw.

(2) Study area to be investigated would be restricted to the main stem of the Missouri River and the Rocky Mountain Area. It was reasoned that the potential pumped storage in Minnesota and Wisconsin, for example, would be used by the participating systems as alternatives when making individual cost comparisons with the NCPS costs for delivered power and energy.

(3) A minimum daily generation capability of 8 hours was established.

(4) Due to losses in pumping-generation cycle, assume pumped-storage plants require approximately 3 kilowatt-hours of pumping energy to provide 2 kilowatt-hours of generation.

(5) Estimated capital costs are based on 1970 price indices. Costs escalated to 1975 figures using escalation factors provided by the Economics Committee.

Preliminary Investigations

A. Plant Sites

The various potential hydropeaking developments shown on Table A have been investigated in varying degrees. Generally speaking, the investigations have been preliminary in nature. A detailed analysis of hydrologic and geological conditions would be required if a particular site is chosen.

Initially it was believed that the addition of more units at the existing Corps of Engineers hydro facilities on the main stem of the Missouri River would be a low-cost source of about 1,200 megawatts of peaking power. The Corps of Engineers is currently undertaking a study to evaluate the hydropeaking potential of the main stem; this study will recognize the many associated problems; e.g., bank erosion, reregulation requirements, construction, etc. The cost estimates will not be available for inclusion in Phase I of this report.

B. Cost Basis

The preliminary construction cost estimates (not including interest during construction) on Exhibit A are based on 1970 cost indices. The Transmission Committee has the responsibility of including all transmission and the generator step-up transformer costs in the transmission plan. Therefore, these costs are excluded from each hydropeaking site.

At the April 6, 1971, meeting of the NCPS Economics Committee the members accepted the Steering Committee's recommendation of using a 5-percent annual escalation figure to obtain the 1975 figure from the 1970 costs. The 1975 capital and O&M costs shown on Exhibit A are based on the 5-percent annual escalation figure.

The preliminary cost estimates of the various hydro sites studied were investigated in varying degrees. In most cases it can be stated the estimates should be considered preliminary in nature because the geology has not been investigated. A detailed investigation of the geology could either increase the reservoir costs significantly or rule out a site completely.

A typical pumped-storage cost estimate based on FPC Reconnaissance Estimating Data is shown in Exhibit B.

C. Plant Operation

For the pumped-storage sites it was assumed that these plants would be operated 8 hours per day for 5 days per week. Assuming about 4 weeks per year for annual maintenance, the annual generating plant factor would be about 20 percent. The peaking period, pumping period and pumping demand for the plants are shown on Exhibit A.

The pumped-storage plants would be operated in the pumping mode from 10 to 14 hours per day to refill the upper reservoir. The costs and size of the reservoir are a function of the number of hours of daily and weekly pumping and generation requirement. If the hydropeaking plants could be utilized, primarily to supply the system or seasonal peak and reserves in lieu of a substantial 8-hour operation, the costs of pumping energy would be reduced significantly.

It is expected that Phases II and III of this study will explore in detail the relationship of the load curves of the specific potential market to hours of generation and to hours of pumping required.

D. Construction Period

The percent expenditure during the construction period for investigation and design, exclusive of time required, is estimated as follows:

Yr. of Construction	% Capital Expenditure
1 yr.	5%
2 yr.	20%
3 yr.	40%
4 yr.	30%
5 yr.	5%

E. Annual Energy Requirement

As indicated earlier it was assumed the pure pumped-storage hydro developments would require 3 kilowatt-hours pumping energy for every 2 kilowatt-hours of generation, due to the losses involved. Assuming an annual generating plant factor of 20%, this would require 2628 kilowatt-hours per year per kilowatt of pumping energy.

POTENTIAL
HYDRO SITES
PUMPED STORAGE
NCPS

NO.	SITE NAME
1.	CUTLER PARK-ROCKWOOD
2.	SHEEP MOUNTAIN
3.	ALCOVA
4.	KORTES
5.	YELLOWSTONE
6.	MOON LAKE
7.	BEAR MOUNTAIN
8.	McDONALDS
9.	UPPER STILLWATER
10.	HAYES RESERVOIR
11.	POUDRE
12.	SWEETWATER
13.	HARDSCRABBLE
14.	TWO FORKS
15.	WEST BEAVER
16.	EIGHT-MILE
17.	POUDRE
18.	WEBSTER
19.	THIEF CREEK
20.	SUNLIGHT
21.	ALLENSPUR
22.	BALD RIDGE
23.	HUNTER MOUNTAIN
24.	FT. BENTON
25.	COW CREEK
26.	FT. PECK
27.	GARRISON
28.	OAHE
29.	BIG BEND
30.	FT. RANDALL

EXHIBIT A
Sheet 1 of 3

Potential Hydropeaking
North Central Power Study

Plant Name Hydropeaking	Type Plant	Location County	Water Source River, Lake, etc.	Add. to Exist. Plant or New Plant	Installed Capacity (MW)
COLORADO					
Sweetwater	PS	Garfield	Sweetwater Creek	New	1,200
West Beaver	PS	Teller	West Beaver Creek	"	320
Hardscrabble	PS	Custer	Hardscrabble Creek	"	500
Eight Mile	PS	Fremont	Eight Mile Creek	"	500
Webster	PS	Park	South Platte River	"	160
Poudre	Conv.	Larimer	Cache la Poudre	"	250
Poudre	PS	Larimer	Cache la Poudre	"	500
Two Forks	Conv.	Jefferson	South Platte River	"	138
MONTANA					
Allenspur	Conv.	Park	Yellowstone River	New	250
Fort Benton	Conv.	Choteau	Missouri River	"	400
Fort Peck	Conv.	Valley	Missouri River	Add.	160
Cow Creek	Conv.		Missouri River	New	720
NORTH DAKOTA					
Garrison	Conv.	Mercer	Missouri River	Add.	240
SOUTH DAKOTA					
Oahe	Conv.	Stanley	Missouri River	Add.	180
Big Bend	Conv. & PB	Lyman	Missouri River	Add.	380
Fort Randall	Conv.	Charles Mix	Missouri River	"	240
UTAH					
Bear Mountain	PS	Uintah	Flaming Gorge Reservoir	New	2,760
Moon Lake	PS	Duchesne	Moon Lake	"	2,224
Yellowstone	PS	Duchesne	Yellowstone River	"	1,080
McDonalds	PS	Wasatch	Jardenelle Reservoir	"	5,220
Upper Stillwater	PS	Duchesne	Rock Creek	"	2,460
Hayes Reservoir	PS	Utah	Diamond Fork Creek	"	1,060
WYOMING					
Beartooth Units					177.5
a. Thief Creek	Conv.	Park	Clarks Fork River	New	125.2
b. Sunlight	Conv.	Park	Sunlight Creek	"	14.9
c. Hunter Mountain	Conv.	Park	Clarks Fork River	"	14.4
d. Bald Ridge	Conv.	Park	Clarks Fork River	"	23
Cutler Park-Rockwood	Conv.	Sheridan	Cutler Creek-Tongue River	"	1,760
Kortes	PS	Carbon	North Platte River	"	125
Alcova	PS	Natrona	North Platte River	"	500
Sheep Mountain (Above Buffalo Bill)	PS	Park	Shoshone	"	1-5,000

Potential Hydropeaking
North Central Power Study

Plant Name Hydropeaking	Installed Capacity MW	No. of Units	Peaking 9 Period Hours	Pumping Requirement Period Hours	Pumping Requirement Demand MW	Pumping Requirement Energy M/KWH	Annual Energy Millions KWH
COLORADO							
Sweetwater	1,200	6	5	10	900	2,365	
West Beaver	320	2	8	12	320	840	
Hardscrabble	500	4	8	12	500	1,315	
Eight Mile	500	4	8	12	500	1,315	
Webster	160	1	8	12	160	420	
Poudre	250	4	2	-	-		186
Poudre	500	4	8	12	500	1,315	
Two Forks	138	2	5	-	-		156
MONTANA							
Allenspur	250	-	-	-	-		638
Fort Benton	400	4	-	-	-		677
Fort Peck	160	2	-				
Cow Creek	720	-	-				1,503
NORTH DAKOTA							
Garrison	240	3	-				
SOUTH DAKOTA							
Oahe	180	2	-				
Big Bend	380	6	-				
Fort Randall	240	3	-				
UTAH							
Bear Mountain	2,760	6	8	12	2,760	7,255	
Moon Lake	2,224	4	8	12	2,224	5,845	
Yellowstone	1,080	2	8	12	1,080	2,840	
McDonalds	5,220	10	8	12	5,220	13,720	
Upper Stillwater	2,460	6	8	12	2,460	6,465	
Hayes Reservoir	1,060	2	8	12	1,060	2,785	
WYOMING							
Beartooth Units	177.5						
a. Thief Creek	125.2	2	-				470
b. Sunlight	14.9	1	-				104
c. Hunter Mountain	14.4	1	-				94
d. Bald Ridge	23	1	-				146
Cutler Park-Rockwood	1,760	-	8	14	1,760	4,625	
Kortes	125	1	8	12	125	328	
Alcova	500	4	8	12	500	1,315	
Sheep Mountain (Above Buffalo Bill)	1-5,000	-	8	14	1-5,000	2,630-13,140	

Potential Hydropeaking
North Central Power Study

	Installed Capacity (MW)	Est. Const. Cost $/KW 1970	Est. Const. Cost $/KW 1975	Est. Annual O&M Cost $/KW 1970	Est. Annual O&M Cost $/KW 1975
COLORADO					
Sweetwater	1,200	138	176	1.25	1.60
West Beaver	320	140	179	1.45	1.85
Hardscrabble	500	165	211	1.35	1.72
Eight Mile	500	182	232	1.35	1.72
Webster	160	223	285	1.75	2.23
Poudre	250	253	323	1.45	1.85
Poudre	500	123	157	1.35	1.72
Two Forks	138	184	235	2.00	2.55
MONTANA					
Allenspur	250	486	620	2.11	2.69
Fort Benton	400	402	513	2.00	2.55
Fort Peck	160	330	421	1.19	1.52
Cow Creek	720	488	623	2.50	3.19
NORTH DAKOTA					
Garrison	240	330	421	1.19	1.52
SOUTH DAKOTA					
Oahe	180	330	421	1.19	1.52
Big Bend	380	330	421	1.19	1.52
Fort Randall	240	330	421	1.19	1.52
UTAH					
Bear Mountain	2,760	90	115	1.50	1.91
Moon Lake	2,224	135	172	1.50	1.91
Yellowstone	1,080	135	172	1.50	1.91
McDonalds	5,220	95	121	1.50	1.91
Upper Stillwater	2,460	120	153	1.50	1.91
Hayes Reservoir	1,060	180	230	1.50	1.91
WYOMING					
Beartooth Units	177.5	807	1030		
a. Thief Creek	125.2	807	1030	2.71	3.46
b. Sunlight	14.9	807	1030	9.26	11.82
c. Hunter Mountain	14.4	807	1030	9.26	11.82
d. Bald Ridge	23	807	1030	7.20	9.19
Cutler Park-Rockwood	1,760	139	177	1.64	2.09
Kortes	125	175	223	2.00	2.55
Alcova	500	111	142	1.35	1.73
Sheep Mountain (Above Buffalo Bill)	1-5,000	175	223	1.50	1.91

Reconnaissance Estimate of Costs for EIGHT-MILE PUMPED-STORAGE PROJECT

Upper Reservoir Storage (Eight-Mile)

Elevation (Ft.)		Area (Ac.)	Storage (AF)
Top of dam	7010		
Max W. S.	7000	122	13,280
Min W. S.	6870	35	2,075
		Active Storage	11,205

Maximum Drawdown = 130 ft.

Lower Reservoir Storage (Soda)

Elevation (Ft.)		Area (Ac.)	Storage (AF)
Top of dam	6000		
Max W. S.	5990	700	40,000
Min W. S.	5920	20	8,300
		Active Storage	31,700

Maximum Drawdown = 70 ft.

Head Determination

H_{max} = 7000 - 5920 = 1080 ft.

H_{avg} = [Max. Elev. Upper Res. - 1/3 (Max. Elev. Upper-Min. Elev. Upper)]

- [Max. Elev. Lower - 1/3 (Max. Elev. Lower-Min. Elev. Lower)]

= [7000 - 1/3 (7000 - 6870)] - [5990 - 1/3 (5990 - 5920)]

= [7000 - 1/3 (130)] - [5990 - 1/3 (70)]

= [7000 - 43.3] - [5990 - 23.3]

= 6956.7 - 5966.7

= 990.0 ft.

H_{min} = 6870 - 5990 = 880 ft.

Reconnaissance Estimate of Costs
for
EIGHT-MILE PUMPED-STORAGE PROJECT

Total Plant Installation

Kw_{total} = C x (H_{avg}) x (Usable Storage in Ac. Ft.)

where "C" is a function of the full load hours per day, and is shown on Chart A.

For 8 hours of equivalent full load peaking, C = 0.045 (from Chart A).

Kw_{total} = 0.045 x 990.0 ft. x 11,205 AF

= 499,183

Use 500,000 kw

Unit Size and Number Determination

Chart B shows that four 125 mw units would be required at a cost of $59 per kw.

1. Cost of Powerplant (Including step-up facilities)

Cost = f x C x F x Total Installed Capacity (Kw)

Where:
- a) f = 0.87 for heads under 1200 ft.
  = 1.20 for heads over 1200 ft.
- b) C = Cost per Kw for a single unit. Determined from Chart B.
- c) F = Cost reduction factor for use in multi-unit installation. Determined from Chart C.

Cost = 0.87 x $59/Kw x 0.78 x 500,000 Kw

=	20,020,000
Less step-up facilities	1,664,000
Net	18,356,000

Reconnaissance Estimate of Costs
for
EIGHT-MILE PUMPED-STORAGE PROJECT

2. Cost of Waterways

Cost = [Vertical Fall (Ft.) + Horizontal Length (Ft.)] x C_t

Where: Vertical Fall = Difference between Min. reservoir Elevs.

C_t = Cost per linear foot in thousands of dollars.

$C_t = 48.94\ K^{0.579}$ where K is the ratio of the total installation in Kw to the maximum head.

Chart D gives C_t = \$1,700/linear foot for $K = \dfrac{500{,}000\text{ Kw}}{1{,}080\text{ Ft.}} = 463$

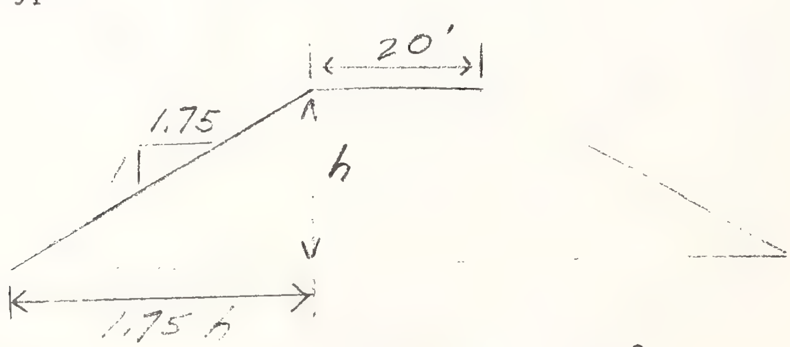
Cost = (950 ft. + 12,050 ft.) x \$1,700/ft.

= \$22,100,000

3. Cost of Reservoirs

The cost of the reservoir is determined from the volume of fill in the dams and dikes. This fill is estimated by assuming a top dam elevation (usually 5 feet above maximum water surface) and taking sections at convenient intervals across the crest.

A typical X - section is:



The area of this section = $20h + 1.75h^2$

To find the volume between two sections, average the two respective areas and multiply this average by the distance (in Ft.) between the two sections. Divide this number by 27 to arrive at an answer in cubic yards.

Reconnaissance Estimate of Costs
for
EIGHT-MILE PUMPED-STORAGE PROJECT

Upper Dam (Eight-Mile)

Point	h(Ft.)	h^2(Ft.^{2})	Area (Ft.^{2})	Ave.Area	Length(Ft.)	Volume (yd.)
0	0	0	0			
				2,687	200	19,904
1	50	2,500	5,375			
				10,675	60	23,722
2	90	8,100	15,975			
				24,073	60	53,500
3	130	16,900	32,175			
				43,075	160	255,259
4	170	28,900	53,975			
				67,675	40	100,259
5	210	44,100	81,375			
				97,875	40	145,000
6	250	62,500	114,375			
				114,375	200	847,222
7	250	62,500	114,375			
				97,875	100	362,500
8	210	44,100	81,375			
				67,675	100	250,648
9	170	28,900	53,975			
				43,075	100	159,537
10	130	16,900	32,175			
				24,075	100	89,167
11	90	8,100	15,975			
				10,675	100	39,537
12	50	2,500	5,375			
				2,682	100	9,933
13	0	0	0			
						2,356,188
				10% for stripping		235,619
				Total Fill		2,591,807

Cost = \$3.30 yd. x 2,591,807 yd. = \$8,553,000

Reconnaissance Estimate of Costs
for
EIGHT-MILE PUMPED-STORAGE PROJECT

Lower Dam (Soda)

Point	h(Ft.)	h^2(Ft.^{2})	Area (Ft.^{2})	Ave.Area	Length(Ft.)	Volume (yd.)
0	0	0	0			
				1,800	100	6,667
1	40	1,600	3,600			
				8,200	180	54,667
2	80	6,400	12,800			
				20,200	500	374,074
3	120	14,400	27,600			
				37,800	700	980,000
4	160	25,600	48,000			
				48,000	580	1,031,111
5	160	25,600	48,000			
				37,800	1,200	1,680,000
6	120	14,400	27,600			
				20,200	3,600	2,693,333
7	80	6,400	12,800			
				8,200	80	24,296
8	40	1,600	3,600			
				1,800	80	5,333
9	0	0	0			
						6,849,481
				10% for stripping		684,948
				Total Fill		7,534,429

Cost = \$2.50/yd. x 7,534,429 = \$18,836,000

Reconnaissance Estimate of Costs
for
EIGHT-MILE PUMPED-STORAGE PROJECT

4. Summation of Costs

		1967 Costs	1970 Costs
A.	Cost of Powerplant	18,356,000	23,863,000
B.	Cost of Waterways	22,100,000	28,067,000
C.	Cost of Upper Dam	8,553,000	10,605,000
D.	Cost of Lower Dam	18,836,000	23,335,000
			85,870,000

5. Land and Land Rights

Cost = 0.046 x (Total Project Cost Excluding Land)

Cost = 0.046 x \$85,870,000 = \$3,950,000

6. Relocations

Relocations and environmental considerations \$1,000,000

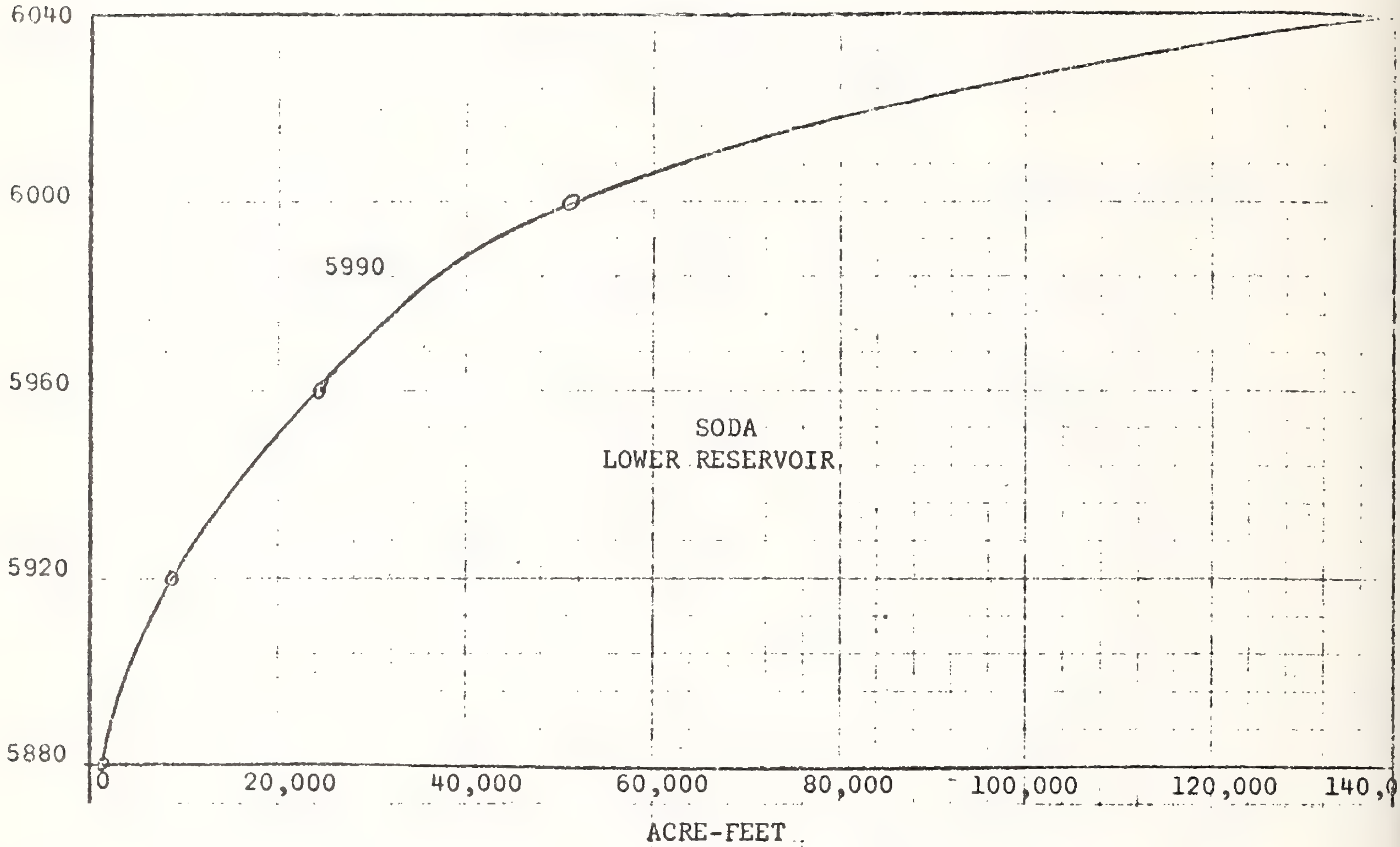
7. Total Cost without Interest During Construction = \$90,820,000

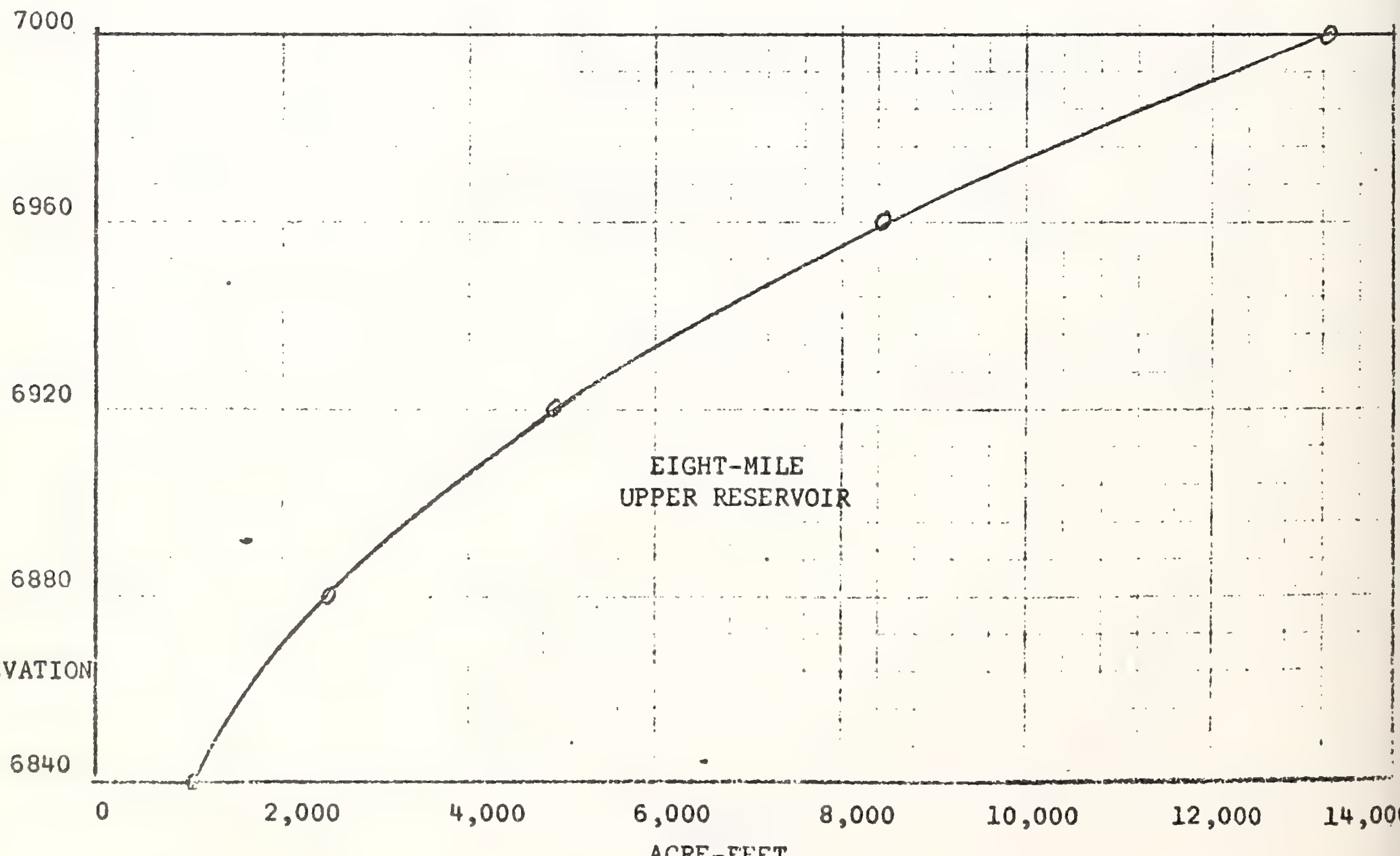
8. Cost per Kw

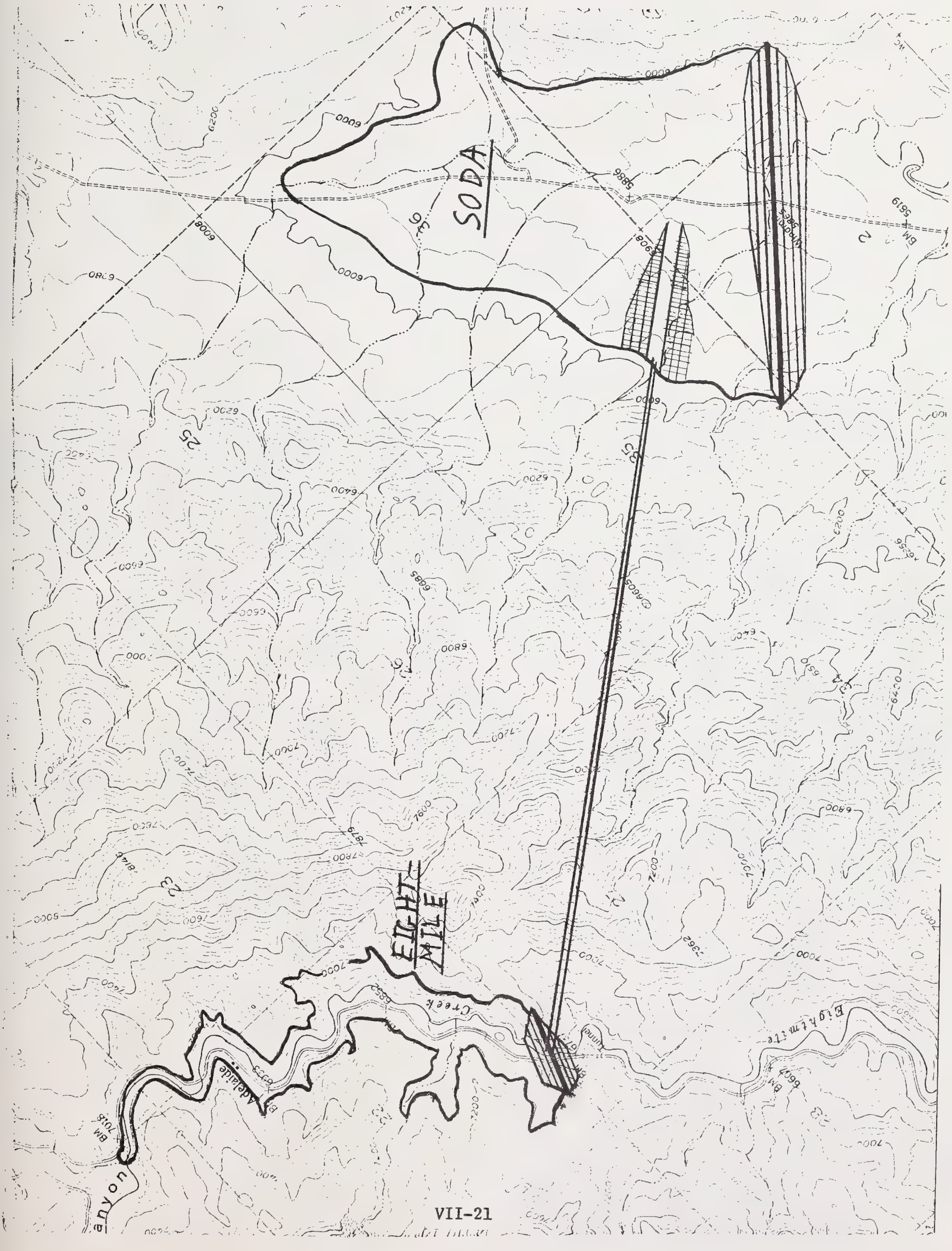
$$\text{Cost/Kw} = \frac{\$90,820,000}{500,000} = \$181.64/\text{Kw}$$

Round to \$182/Kw

CAPACITY CURVES







SODA
EIGHT-MILE
Creek
Eightmile
Adelaide
anyon

VIII. THERMAL GENERATION

NORTH CENTRAL POWER STUDY
THERMAL GENERATION TASK FORCE
Thermal Generation Cost Estimates
Appendix

I. The Thermal Generation Task Force was initially assigned the work of estimating capital and operating costs for subbituminous coal-fired generating units assumed to be located close to mining in the Colstrip-Gillette area. Later in the study the request was made to consider the effect of burning Lignite in the Beulah-North Dakota area. Most of the guidelines for the estimates were recommended by the Steering Committee and other task forces.

The following listing represents the guidelines, assumptions and limitations which apply to the cost estimates in this report.

1. Develop net capital costs per installed kilowatt for 2 - 500 MW units and 2 - 1000 MW units to be operational in 1970. Then escalate at an annual rate of 5% (compounded) to 1975, as directed by the Economics Committee. The term "net capital cost" assumes that the cost per kw shown includes 5% of the unit capacity to cover capital costs for "in plant" power requirements.

2. No capital cost benefit is assumed for more than two units at a site.

3. Interest during construction is excluded but will be covered by the Economics Committee.

4. Ad valorem taxes during construction are excluded but will be covered by the Economics Committee.

5. Operating and maintenance costs do not include Administrative and General charges which will be covered by the Economics Committee.

6. Semi-enclosed plants.

7. Step-up transformers are excluded from this study but will be included in transmission costs.

8. Land cost is shown as an additional estimated capital cost per MW of installed capacity.

9. Land reclamation costs, as developed by the Land Reclamation Task Force for strip mining, are listed as an additional expense item per ton of coal consumed.

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10. Other land reclamation and related recreational costs are excluded.

11. The capital costs of generation shown include a cost increment for induced draft wet cooling towers, which for reference is also separately listed. It is assumed that the cost of effluent or blowdown pond is included in the estimated cooling tower costs.

12. At sites where the delivery of adequate water for wet cooling tower operation might be a problem, the estimated costs for dry tower cooling are detailed.

13. Ash disposal is not included in the Operation and Maintenance but is separately listed under the assumption that the ash will be deposited in the mined-out area before replacing the overburden.

14. A plant factor of .85 is assumed throughout the study.

15. An amount for precipitation is included in capital costs but is also separately listed.

16. For subbituminous coal-fired plants, the construction and operating costs are assumed to be for relatively low ash coal, with a sulphur content below 1%.

II. UNIT CAPITAL COST DATA

For development of reasonable unit cost estimates, the Thermal Generation Task Force accumulated recent cost data on several units of various sizes that had been planned or were near completion. The cost estimates were adjusted to simulate, as nearly as practical, equivalent timing and comparable features under the stated guidelines.

The estimates were then adjusted for equivalent scale of size by means of an exponential formula in which a factor of .65 was used. By this means, several estimated costs for 2 - 500 MW units in 1970 were produced. The average of these figures was used to develop, by use of the exponential curve, the estimate for 2 - 1000 MW units in 1970. Due to the lack of definitive cost data on 1000 MW units, the known data on 700 - 800 MW units were used, and it was assumed that the exponential curve could be extended to the larger size.

The 1970 estimates were then escalated to 1975 levels using the 5% annual compound interest rate as recommended by the Economics Committee.

III. ADJUSTMENT FOR UNIT SCALE OF SIZE*

This information is offered for the convenience of those who are interested in applying the exponential formula.

The computation is an expression of the usual reduction in cost per unit of rating as machine capacity is increased when comparing similar types of equipment. The cost change typically follows an exponential curve that can be used to develop unit cost estimates by using the appropriate factor. This study uses .65 which appeared to best fit the curve against available reference data.

The formula is:

$$\text{Cost of Unit A in \$/kw} = \text{Total Cost of Unit B} \left(\frac{A}{B}\right)^{.65} \div A$$

where, A = capacity in kw of the unit with cost/kw unknown

B = capacity in kw of the unit with cost/kw known

* - Reference:
J. D. Constance, P.E.
"Six-tenths Factor Gives Cost Change"
Power, September, 1969

EXAMPLE NO. 1 (slide rule accuracy)

From an estimated cost of \$158/kw for a 500 MW units, produce the estimated cost/kw for a 1000 MW unit:

$$500{,}000 \times \$158 = \$78.8 \text{ million } \left(\frac{1000}{500}\right)^{.65} \div 1{,}000{,}000$$

$$= \left(\frac{75{,}000{,}000 \times 1.569}{1{,}000{,}000}\right) = \$124.00/\text{kw for a 1000 MW unit}$$

EXAMPLE NO. 2

From an estimated cost of \$124.00/kw for a 1,000 MW unit, produce the estimated cost/kw of a 500 MW unit.

$$\$124.00 \times 1{,}000{,}000 = \$124. \text{ million } \left(\frac{500}{1000}\right)^{.65} \div 500{,}000$$

$$= \left(\frac{124{,}000{,}000 \times .637}{500{,}000}\right) = \$158/\text{kw for a 500 MW unit}$$

IV. ESTIMATED GENERATING UNIT NET CAPITAL COSTS PER KILOWATT

The following estimated costs are intended to be net figures which are developed from gross costs by assuming that 5% of the plant output is dedicated to the plant energy requirements. The net unit output for covering load is the 500 MW or 1000 MW amount.

The resulting costs agree in order of magnitude with FPC information and with other published studies. These appear to be reasonable mid-range estimates which are assumed to apply under Section I guidelines. Escalation from 1970 to 1975 is 5% annually (factor of 1.276.)

Generation Unit Capital Cost per Net Kilowatt
(Average for 2 units)

Unit Size MW	1970	1975
2 - 500	$158	$202
2 - 1000	$124	$158

The generation capital cost per net kilowatt is assumed to include an increment for induced draft wet cooling and an increment for precipitation. These cost increments per kilowatt are:

Unit Size MW	1970	1975
2 - 500		
Precipitator -	$8.50	$11.00
Induced draft wet cooling tower -	8.50	11.00
2 - 1000		
Precipitator -	7.00	9.00
Induced draft wet cooling tower -	7.00	9.00

V. LAND CAPITAL COST

The capital cost of land could vary widely according to the number and types of competitive alternative uses for which it is suitable. In the areas under consideration the competitive uses appear to be limited, and an arbitrary value of $100/acre is assigned for the 1970 cost.

For a relatively small generating complex of 2000 MW, a land area of 1000 acres, or .5 acre per Megawatt, would appear reasonable. At $100 per acre this would be $50. per Megawatt or 5¢ per kilowatt for capital cost of land. The added land requirement for larger individual complexes would be less per Megawatt, possibly .2 acre per MW. Under these assumptions, it is apparent that land cost is a small part of the total generation capital cost. However, in response to the study guidelines, the Thermal Generation Task Force suggest the following levels in which the 1970 estimate is escalated 5% annually to 1975.

Land Capital Cost Per Megawatt of Capacity

1970	1975
$50.	$65.

VI. ANNUAL PERCENT OF TOTAL PROJECT CAPITAL EXPENDITURES DURING CONSTRUCTION

These estimates would approximate the percent of total capital expenditures year by year during the construction period for one unit.

Construction Years	1st	2nd	3rd	4th
% of total cost	10%	30%	50%	10%

VII. LAND RECLAMATION

The Land Reclamation Committee estimated that strip mining reclamation would cost between 1 and 4 cents per ton of coal mined when overburden averaged 40 feet to 135 feet in thickness. On this basis the average 1970 cost could be 2.5¢ per ton of coal mined. At 5% annual escalation, the 1975 cost would be approximately 3.2¢ per ton of coal.

VIII. OPERATION AND MAINTENANCE

The estimated O. & M. was developed from FPC-38 Supplement #1 to FPC-35 report. Administration and General charges are not included. The costs are on the basis of an 85% plant factor. Escalation from 1970 to 1975 is at the recommended 5% for 5 years compounded (factor of 1.276).

Unit Size MW	Net O. & M. 1970	1975
2 - 500 MW O. & M. in mills/kwh	.45 mills	.57 mills
" " " " " " " $/MW year	$3,900.	$5,000.
2 - 1000 MW O. & M. in mills/kwh	.25 mills	.32 mills
" " " " " " " $/MW year	$2,200.	$2,800.

Costs for ash disposal, scrubbing, and water are not included.

It was suggested that the cost of disposing of a ton of ash might be equal to the cost of a ton of coal, when the ash is returned to the mined out area. On this basis, the cost of ash disposal, assuming 10% ash, is estimated at:

.1 mill/kwh
$876./MW year

Costs of water are presented in the Water Supply Task Force reports. The assumed annual water consumption at 100% plant factor is 20,000 acre feet per year for each 1,000 MW of generation. This total consumption amounts to 28 CFS for 1,000 MW. At 85% plant factor, the annual water consumption would then be 17,000 acre feet per 1,000 MW.

IX. NET HEAT RATES

Estimated heat rates were developed from data presented in FPC-38, Supplement #1 and are assumed to be net figures for 85% plant factor.

Unit Size	Net Heat Rate
500 MW	9500 Btu/kwh
1000 MW	9100 Btu/kwh

X. UNIT AVAILABILITY

EEI published a report in 1970 that compiled the forced outages and maintenance schedules being projected by various reliability councils, power pools and individual systems for various sizes and types of units. These projections varied widely; therefore, approximate averages for mature plants (after 3-years operation) were assumed, which are:

Unit Size	Maintenance Outage	Forced Outage	Total Outage	Plant Availability
500 MW	8% (4 weeks)	5%	13%	87%
1000 MW	8% (4 weeks)	7%	15%	85%

XI. COAL CONSUMPTION AND COST CURVES

For convenient reference, two curves (#1 & #2) are attached, which indicate coal consumption in tons per million kwh and tons per megawatt year when particular heat rates and coal heat content figures are known:

Curve #3 attached indicates fuel cost in mills per kwh when fuel cost per million Btu and the net heat rate are known.

According to the Coal and Byproducts Task Force, the coal cost is a mine mouth price. It has been suggested that transportation from mine to generating site could be estimated at 3% of the coal cost. Therefore, coal costs should be multiplied by 1.03 for 1970 costs and by 1.04 for 1975 costs to cover the handling.

To calculate the tons of fuel consumed annually by one installed megawatt of capacity at an assumed plant factor, the formula is:

For example with a plant factor of .85

$$\text{Tons/MW/year} = \frac{\text{Net heat rate in Btu per kwh} \times 8760 \times .85 \times 10^6}{\text{Btu heat content per ton of coal}}$$

To calculate the tons of fuel consumed by the production of one million kwh of energy, the formula is:

$$\text{Tons/million kwh} = \frac{\text{Net heat rate in Btu per kwh} \times 10^6}{\text{Btu heat content per ton of coal}}$$

XII. BEULAH LIGNITE RELATIVE COSTS

The additional cost increments involved with burning Beulah-North Dakota Lignite in addition to the costs of burning the Montana-Wyoming subbituminous coal were estimated under the following assumptions, based on 500 MW units and assumed 1970 data.

1. The cost of the Lignite boiler would be $8 million more than for subbituminous fuel. This amounts to $16./kw for a 500 MW unit.

2. The net heat rate when burning the Lignite will be higher. According to data from the "Missouri River Basin Comprehensive Framework Study of Water Requirements for Thermal Generation", January, 1967, the heat rate could be estimated at 10,500 btu/kwh for Lignite.

3. The cost of cooling water in the Beulah area is less than the water cost in the Colstrip-Gillette area. These amounts, as determined by the Water Supply Task Force, are now based on a consumption rate of 28 CFS for a 1,000 MW unit. The estimated costs per kwh (.85 plant factor) for water delivered to Beulah, Colstrip and Gillette indicate a relatively low cost increment for water consumed.

   The estimated costs are:

Beulah	water cost/acre ft.	\$30 =	.06 mill/kwh
Colstrip	" " " "	\$45 =	.09 " "
Gillette	" " " "	\$93 =	.18 " "

   Under the guidelines of the North Central Power Study, water was to be delivered to mine mouth generating stations. However, in a specific location, where a serious detailed economic study was being made, the cost of water development and plant location would be tested for the optimum arrangement, especially when the water might be available at no cost.

4. The estimated cost of Lignite is roughly 2¢/million Btu higher than the subbituminous Montana-Wyoming coal based on NCPS Coal and By-Products Task Force data.

5. The O. & M. for Lignite burning units was assumed to be the same as for the Montana-Wyoming fuel. In practice, the O. & M. might be higher when burning Lignite. Also ash disposal might be a higher figure for Lignite.

The above guidelines indicated a net higher cost for burning Lignite of .55 mill/kwh when using 11.7% annual fixed charges and 85% plant factor. Water costs differences are additional. No additional O. & M. was assumed.

I. D. C., ad valorem taxes, and ash disposal are not included in the .55 mill figure. As an indication of the degree of sensitivity to taxes, ad valorem taxes when applicable would be higher for Beulah by .02 mill/kwh assuming 1% tax on the additional \$16. per kw boiler investment.

XIII. BTU RATINGS OF LIGNITE vs SUBBITUMINOUS COAL

For those who are interested in coal classifications, the heat ratings of Lignite and subbituminous coals have been established on a Btu per pound basis by the American Society for Testing and Materials in its report ASTM D388-64T, as follows:

Calorific Value Limits BTU Per Pound
With Moisture as Received (No Visible Water)
But On A Mineral-Matter-Free Basis

		Equal to or Greater Than	Less Than
Subbituminous	A Coal	10500	11500
"	B "	9500	10500
"	C "	8300	9500
Lignite	A	6300	8300
"	B		6300

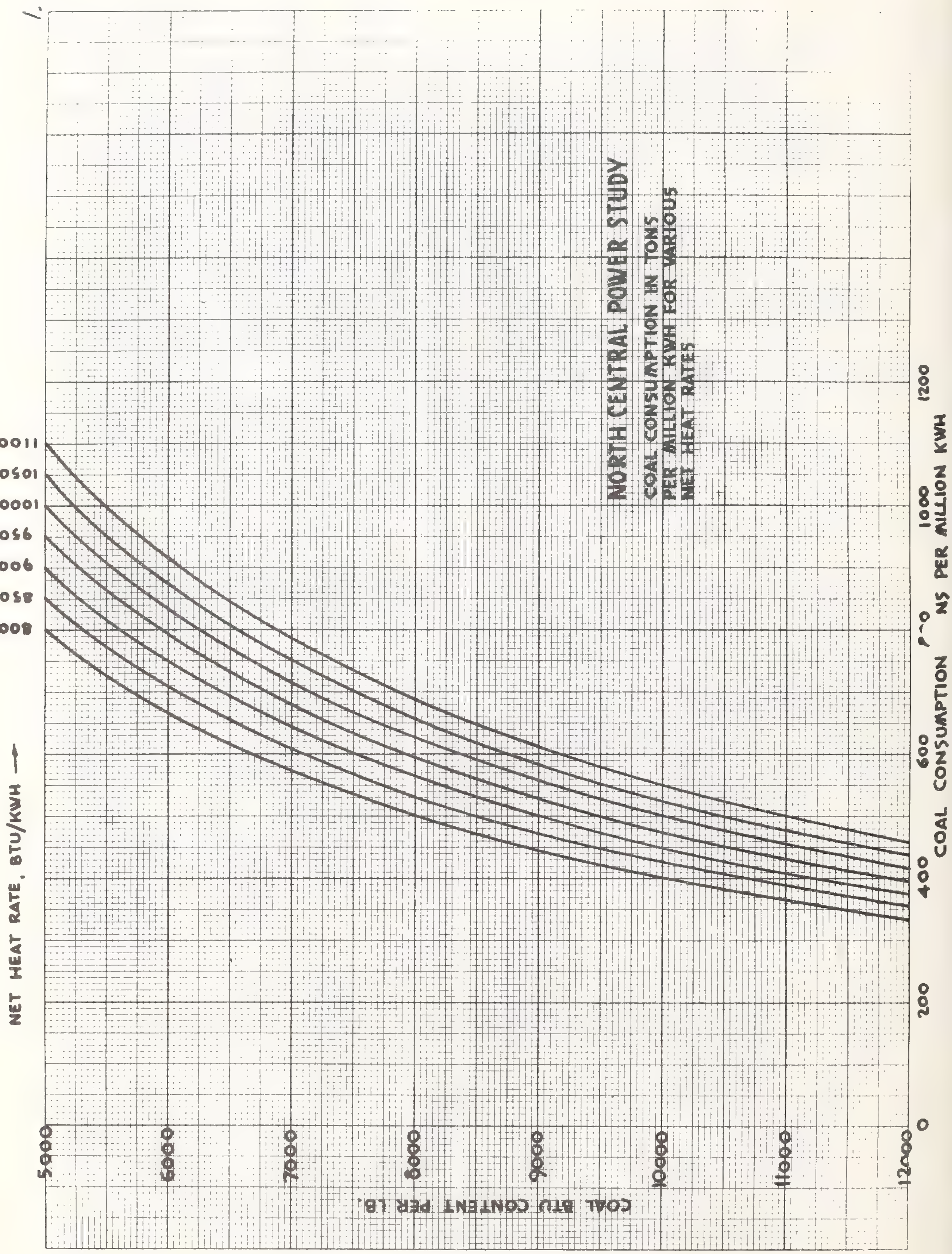
XIV. DRY COOLING COST ESTIMATES

If dry mechanical draft cooling towers are incorporated in the plant design the following items must be considered. Also, any cost adders in other data presented for wet cooling towers must be subtracted from the plant capital costs before applying the following items.

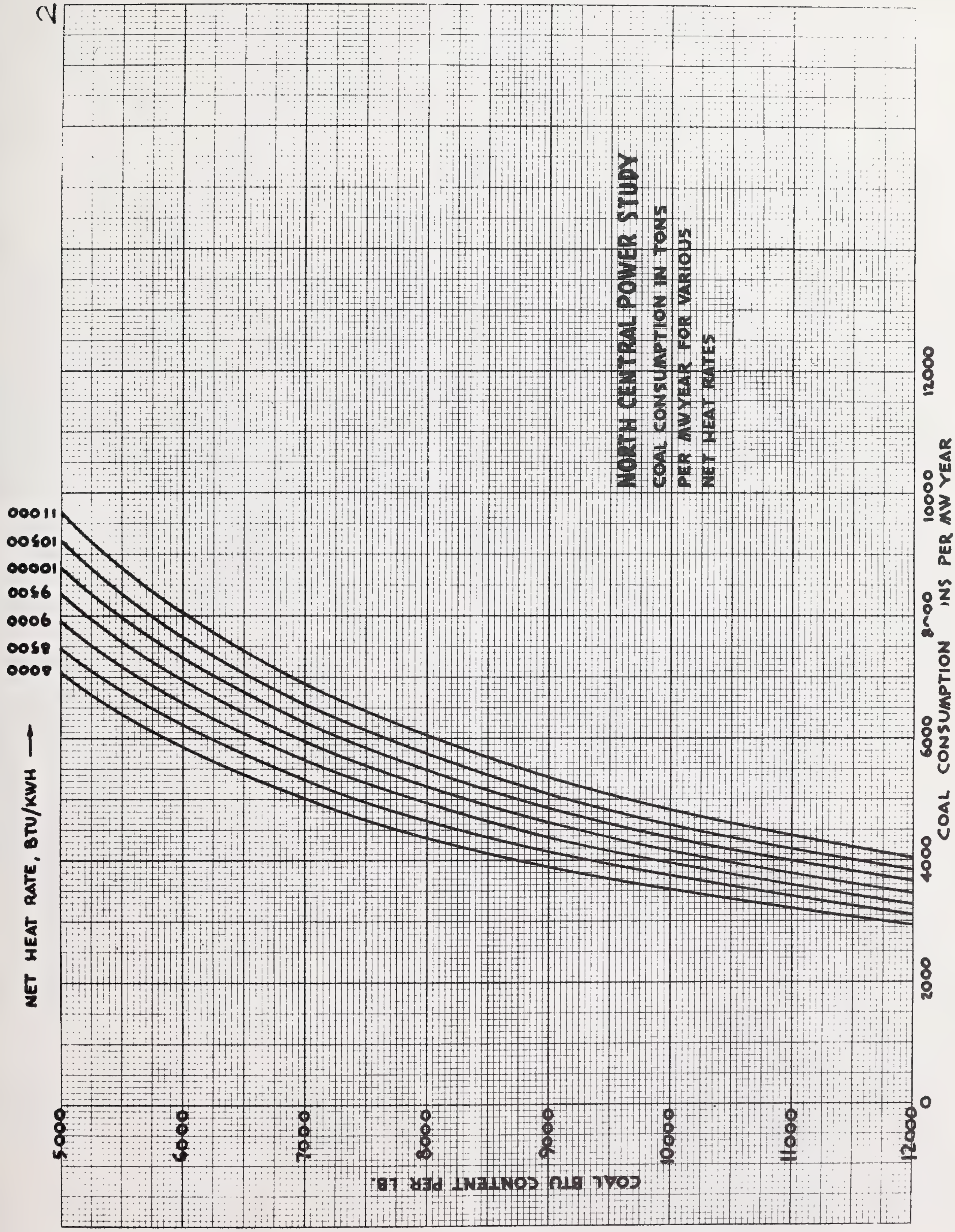
Plant Performance Factors	500 MW	1000 MW
Unit Net Heat Rate Btu/kwh	10,400	10,000
% Increase in Turbine Size	1.5	1.5
% Increase in Boiler Size	12.0	12.0
% Increase in Heat Rejection System Size	25.0	25.0
Unit Design Turbine Backpressure inches of Hg	10.0	10.0

Plant Cost Factors	1970	1975
Capital Costs		
2- 500 MW Units $/kw	$23.00	$29.00
2-1000 MW Units $/kw	21.00	27.00
O. & M. Costs		
2- 500 MW Units Mills/kwh	0.53	0.67
2-1000 MW Units Mills/kwh	0.31	0.39

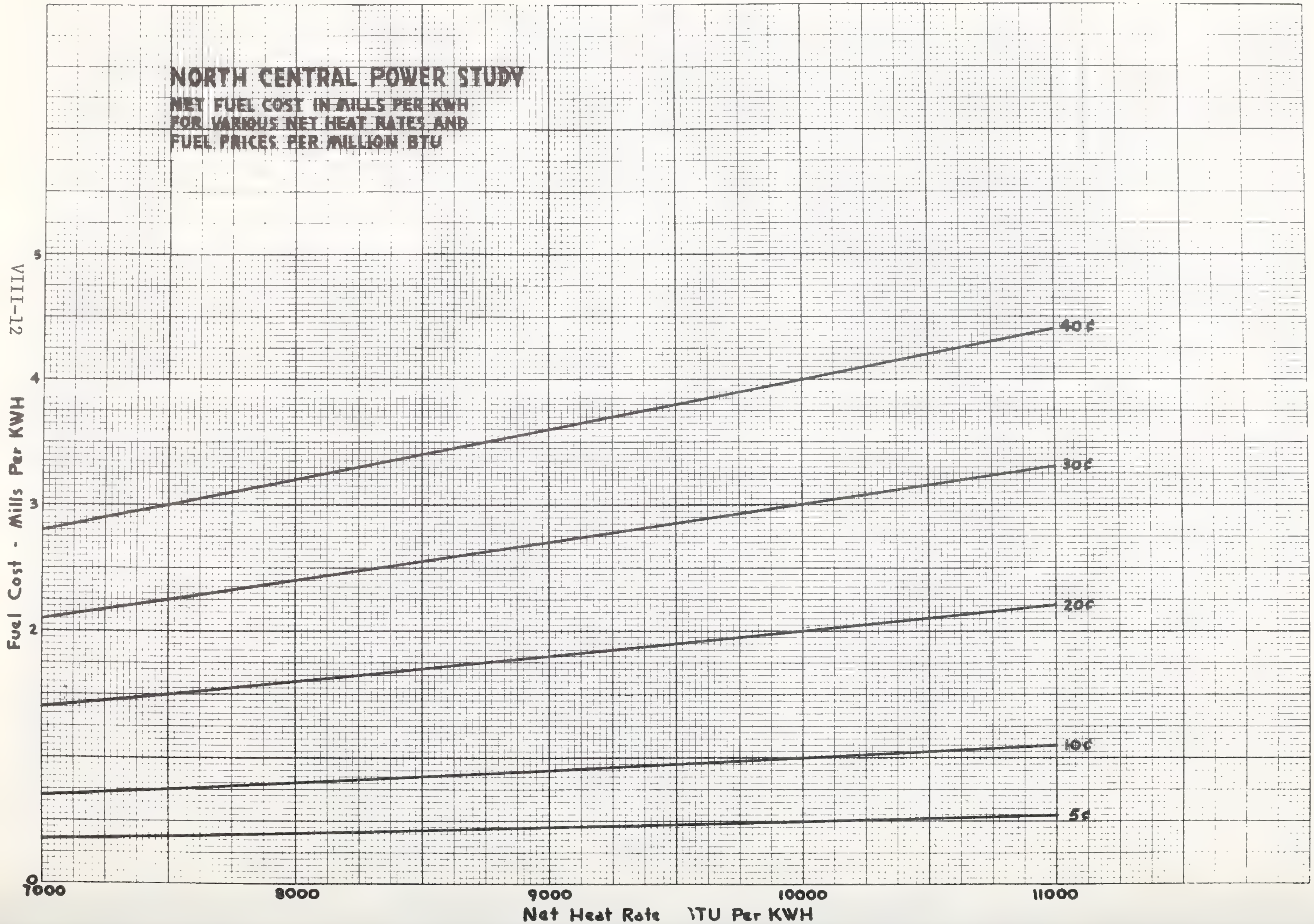
The above factors assume that, instead of derating a unit, that additional capacity would be installed to retain the rated output under the listed operating conditions. It should be remembered that there is not a dry cooling tower of the size listed in service on a power plant anywhere in the world at this time. The costs and sizing factors are typical values expected for plant constructed from 5000 to 7000 foot elevation.


NORTH CENTRAL POWER STUDY
COAL CONSUMPTION IN TONS PER MILLION KWH FOR VARIOUS NET HEAT RATES
NET HEAT RATE, BTU/KWH
11000
10500
10000
9500
9000
8500
8000
COAL CONSUMPTION NS PER MILLION KWH
0
200
400
600
1000
1200
COAL BTU CONTENT PER LB.
5000
6000
7000
8000
9000
10000
11000
12000

2.


NORTH CENTRAL POWER STUDY
COAL CONSUMPTION IN TONS
PER MW YEAR FOR VARIOUS
NET HEAT RATES
NET HEAT RATE, BTU/KWH
11000
10500
10000
9500
9000
8500
8000
COAL BTU CONTENT PER LB.
5000
6000
7000
8000
9000
10000
11000
12000
COAL CONSUMPTION
PER MW YEAR
0
2000
4000
6000
10000
12000

3.


NORTH CENTRAL POWER STUDY
NET FUEL COST IN MILLS PER KWH
FOR VARIOUS NET HEAT RATES AND
FUEL PRICES PER MILLION BTU
40¢
30¢
20¢
10¢
5¢
0
2
3
4
5
Fuel Cost - Mills Per KWH
7000
8000
9000
10000
11000
Net Heat Rate BTU Per KWH

IX. WATER SUPPLY

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APPENDIX
WATER SUPPLY

Purpose

This appendix report summarizes the activities of the Water Supply Task Force of the North Central Power Study. The Task Force was charged with exploring water resources availability, location and quality, and costs of water delivered to a potential mine-mouth steam electric generating plant.

Scope

Geographical

The study of water resources availability is broad in geographical scope. It encompasses plans for delivery of water to twenty coal fields in Montana, two in North Dakota, one in South Dakota, six in Wyoming, and one in Colorado, north of Denver.

Functional

The study deals only with facilities needed to deliver the required quantity of water to potential steam electric generating plants. It was assumed that water would be delivered in harmony with existing water rights, water laws, and with least disturbance of the natural environment as required by the National Environmental Act of 1969 (P.L. 91-190).

Technical

Many and varied technical problems of hydraulic and structural design will probably be encountered by subsequent investigations and designers. However, the Task Force did not consider any problems insurmountable insofar as constructing facilities to deliver the required amount of water is concerned. The members of the Task Force assumed that disciplinary personnel would be available to plan, design, and construct the water conveyance facilities. The flow of water for each size contemplated steam-electric plant is considered to be the minimum delivery for continuous operation of the generating plant.

Level of Technology

The plans and estimates of cost are predicted on 1970 level of technology for construction and materials of construction.

Water Supply

Water Resources

The Bureau of Reclamation has authorization currently to annually option 775,000 acre-feet of water to industry from the Wind-Bighorn River. Capability of the storage and water resource for industrial uses is about 1,000,000 acre-feet at Hardin, Montana. There have been contracts executed in the amount of 658,000 acre-feet and requests are pending for 295,000 acre-feet. An interest has been indicated in an additional 100,000 to 200,000 acre-feet.

Other immediately available sources of industrial water are from Fort Peck and Garrison Reservoirs. Probable availability is at least 1,000,000 acre-feet.

Potential water supplies which could be developed for industrial uses as needed, on an annual firm basis, are as follows:

	Acre-Feet
Powder River and Moorhead Reservoir	100,000
Tongue River and New Reservoir	60,000
Little Bighorn River and Reservoir	40,000
Little Missouri River and Reservoirs	80,000
Green River and Aqueduct to Platte River	100,000
Buffalo Bill Reservoir Enlargement, Wyoming	50,000
Yellowstone River surplus flows as firmed by offstream storage	450,000
Total	880,000

An estimate of water supplies which could be used, or developed and utilized, for coal development would thus be at least 2.8 million acre-feet of which about 1.7 million acre-feet are not presently under consideration except in connection with North Central Power Study.

Water Quality

The Federal Water Quality Standards regarding thermal pollution permits an 18° F. rise in cooling water discharged from potential steamplants to the streams. These conform to the criteria contained in the Missouri Basin Comprehensive Study and were used in the estimation of water requirements for flow-through type of cooling contained herein.

Further, it was assumed that all boiler feed water and cooling water would be usable with only nominal treatment to remove deleterious matter from the water. The computations of water requirements do not consider quality of water even though the final analysis of water cost will include treatment to remove undesirable minerals or the increased maintenance costs to overcome deleterious effects of boiler feed water.

Water Requirements for Thermal Generation Plants

The annual water delivery requirements are predicated on single steamplants operating at 85 percent load factor. The requirements do not reflect conduit seepage or operational wastes. The daily delivery is based on meeting the average maximum day water requirement without daily peak capacity for refill of storage ponds, etc.

Three types of water cooling facilities were considered when computing water requirements for the powerplants; i.e., wet cooling tower and appurtenant facilities for dissipating superfluous heat energy, cooling ponds, and flow-through type of cooling facilities. Make-up boiler feed water was assumed to be 0.5 cubic feet per second per 1,000 megawatts of installed capacity.

The bases for estimating water requirements are as follows:

1. Assume average of 9,500 BTU per pound of coal for each net kilowatt-hour.

2. Individual plant capacity factor at 85 percent per year for water requirement computations.

3. Make-up boiler feed water at 0.5 c.f.s. per 1,000 megawatts of installed capacity.

4. Heat cooling water requirement at 550 g.p.m. per megawatt.

5. Evaporation:

a. Wet cooling tower - 1.47 A.F./Kilomegawatt-Hour

b. Cooling pond - 1.10 A.F./Kmwh

c. Flow through from stream source - 0.92 A.F./Kmwh

6. The feed water would be usable with only nominal treatment to remove deleterious matter from water.

Each 1,000-megawatt steamplant operating 24 hours per day, 365 days per year, would generate 8,760 million kilowatt-hours of electrical energy or proportionately less depending on the plant load factor. The water requirement estimations listed in Table 1 on an annual and daily basis for wet-tower cooling and cooling pond for dissipating superfluous heat from condenser cooling water are based on the above criteria.

Table 1.--Water Requirements - Steamplants 1/

Steam Plant Size	Boiler Feed Loss	Wet Tower Evaporation Loss	Water Requirements Total Delivery 2/	Cooling Pond Requirements Evaporation Loss	Cooling Pond Requirements Total Delivery 2/
Megawatts	c.f.s.	c.f.s.	A.F./yr.	c.f.s.	A.F./yr.
1,000	0.5	17.5	10,950	13.5	8,690
3,000	1.5	53	32,830	39.5	24,570
5,000	2.5	88	54,750	68	43,450
10,000	5.0	175	109,500	137	86,900

1/ Operating at 85 percent load factor annually.
2/ Includes boiler feed make-up water.

The estimation of water requirements for the flow-through type of cooling is based on the aforementioned criteria plus the assumption that an 18° F. rise in cooling water temperature discharged from the steamplant to the stream will be permitted under the Federal Water Quality Standards regarding thermal pollution. Evaporation loss from a 1,000 MW steam-electric plant with flow-through cooling would be about 8,060 acre-feet per year or 6,500 acre-feet at 85 percent load factor. Only five plant sites are located close enough to streams so that flow-through-type cooling for steam-electric plants could be practicable. These are Birney, Birney-PJ, and Decker adjacent to the Tongue River; Broadus and Moorhead adjacent to the Powder River. Insufficient water flows in these two streams to cool large steam-electric powerplants by flow-through type of cooling and maintain the 18° F. limit in stream temperature rise. Water requirements on these criteria for flow-through-type cooling of condensers have been estimated to be 0.001803 acre-feet per kilowatt-hour per degree F. rise in water discharging from the plant or 746,000 acre-feet per year to cool a 1,000-megawatt plant operating at 85 percent load factor. Total annual diversion requirement would be 752,500 acre-feet.

Plan of Investigation

Maps and Surveys

The route studies of water conveyance facilities consisted generally of layouts on one-degree quadrangle maps, scale 1 : 250,000, of the Army Map Service. Where quadrangle maps of the $7\frac{1}{2}$-minute series of an area were available, layouts and siting conditions were made more realistically. No field surveys nor maps were made of any site or route for the Task Force study. Water conveyance routes and steamplant locations are shown on Map X-600-194. In general, the right-of-way take was assumed to be 200 feet wide. Access roads were included wherever necessary to insure site accessibility.

Hydraulic Assumptions

The pipelines, pumping plants, flow-control structure, and other appurtenant facilities were sized to deliver the maximum daily water requirements plus 10 percent. The pipelines were sized using Scoby's coefficient of roughness equal to 0.37 and n = 0.014 of the Manning Formula. Each delivery plan included a terminal storage pond capable of meeting a three-day delivery demand. Each pond could be refilled during peak operations because the main conveyance pipeline would be oversized by 10 percent of maximum daily requirements. Reuse of water was considered to the extent that it may be more economical to reclaim and reuse water than to deliver new water to the site. Disposition of mineral effluents was assumed to be a part of plant costs and not a water delivery cost. Accordingly, it is not considered in the cost of water to be delivered.

The number of pumping lifts was determined from the total lift. Pump lifts were limited to about 250 feet maximum where possible. Flow-control structures were used wherever gravity flow was present in a portion of the line. They were used at each 150-foot drop in elevation along the line. Hydraulic head loss was assumed but not computed for inlet channels where necessary and for chlorination stations, terminal storage, etc. Control buildings and telemetry equipment would be included as part of the operating facilities of the conduit.

Structural Design Assumptions

The derivations of costs were predicated on average foundation conditions at all structure sites and conduit routes and the assumptions that any foundation deficiency could be overcome without abnormal costs involved. The structural safety of the facilities would be guaranteed against overloading by use of proper facilities such as forebays, surge tanks, air valves, accessory mechanical and electrical equipment, etc. Pertinent physical data of each plan are summarized in Table 2.

Method of Cost Estimation

Pipeline sizing was based on studies of economical size pipe for various flows, hydraulic head, and structural safety. After computor runs were made and sizing studies of pipelines completed, pipe costs were determined for each pipe head class increment (50 feet). Pipeline costs were then determined from cost curves which include earthwork, furnishing, and laying pipe. An adequate allowance was included to cover contingencies, horizontal and vertical blocking, blowoff valves, air inlet and release valves, highway and stream crossings. Costs of complete pumping plants, except electrical transmission lines, flow-control structures and attendant regulating tanks, inlet

Table 2.--Physical Data

North Central Power Study

Plant Location	Coal Deposit	Plant Size (MW)	Conduit Diameter (Inches)	Conduit Length (Miles)	No. of Pumping Plants	Average Installation (HP/Plant)	Annual Energy at Load Center (Million Kwh)	Annual Water Delivery 1/ (A.F./Yr.)
North Dakota								
Bowman #1	Slope & Bowman	5,000	54	29.0	3	4,600	47.0	55,000
Bowman #2	Slope & Bowman	5,000	54	122.2	11	3,300	175.5	55,000
N of Dickinson	Heart River	3,000	42	43.0	4	2,000	39.0	33,000
Dickinson	Heart River	3,000	42	59.5	6	2,300	67.0	33,000
Dickinson and	Heart River	(3,000)	66	59.5	6	4,800	150.0	(88,000)
Bowman	Slope & Bowman	(5,000)	54	62.7	5	3,300	78.0	55,000
Beulah	Knife River	5,000	54	21.0	2	2,900	28.0	55,000
Center	Center	1,000	24	17.0	4	640	12.3	11,000
South Dakota								
Ludlow	Cave Hills	1,000	24	30.8	5	770	18.0	11,000
Colorado								
Watkins	Denver Basin	1,000	24	20.0	4	960	14.0	11,000
Wyoming								
W of Kemmerer	Adaville	5,000	54	35.8	5	4,000	89.0	55,000
NE of Rock Springs	Jim Bridger	1,000	24	37.7	9	800	27.0	11,000
N of Wamsutter	Red Desert-Cherokee	5,000	54	82.1	6	3,800	112.0	55,000
Gillette Vicinity, 10 Plants	Gillette	10,000		(St. Xavier				110,000 ea.
Spotted Horse	Spotted Horse	3,000			to Gillette			33,000
Lake DeSmet	Lake DeSmet	10,000					Aqueduct)	110,000

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Table 2.--Physical Data (continued)

North Central Power Study

Plant Location	Coal Deposit	Plant Size (MW)	Conduit Diameter (Inches)	Conduit Length (Miles)	No. of Pumping Plants	Average Installation (HP/Plant)	Annual Energy at Load Center (Million Kwh)	Annual Water Delivery [1/] (A.F./Yr.)
Montana								
NW of Brockway	'S' Bed	5,000	54	44.6	5	4,000	84.0	55,000
Paxton	Carroll	1,000	24	32.3	5	960	17.0	11,000
Richey	Lane	1,000	24	38.2	7	900	22.0	11,000
Fort Kipp	Fort Kipp	1,000	24	2.0	1	640	3.0	11,000
Reserve	Reserve	1,000	24	39.5	6	900	17.0	11,000
Coal Ridge	Coal Ridge	1,000	24	46.5	8	880	24.0	11,000
Wibaux	Beach-Wibaux	5,000	54	27.5	5	3,400	70.0	55,000
W of Savage	13 Mile Creek	1,000	24	18.2	4	1,000	15.0	11,000
Colstrip	Colstrip	5,000	54	31.0	4	4,500	78.0	55,000
NW of Brandenburg	Sweeney Creek	1,000	24	12.0	3	800	10.0	11,000
SE of Ashland	Otter Creek	5,000	54	12.0	2	2,500	19.0	55,000
Birney	Birney	1,000	(Plant located adjacent					11,000
Birney-PJ	Poker Jim-Lookout	1,000				to Tongue River)		11,000
S of Birney	Hanging Woman Creek	10,000	72	11.0	2	8,400	53.0	110,000
Kirby Alt. 1	Kirby	1,000	24	17.0	5	940	21.0	11,000
Kirby Alt. 2	Kirby	1,000	24	17.0	3	780	10.0	11,000
Decker	Decker	5,000	(Plant located adjacent to Tongue River)					55,000
Volborg	Foster Creek	5,000	54	46.0	5	4,700	76.0	55,000
Camps Pass	Pumpkin Creek	10,000	72	66.0	7	7,700	228.0	110,000
Sonnette	Sonnette	1,000	24	16.1	5	880	20.0	11,000
Broadus	Broadus	3,000	(Plant located adjacent					33,000
Moorhead	Moorhead	5,000				to Powder River)		55,000

1/ Based on 17.5 c.f.s./1,000 MW of steamplant capacity.

channels, chlorination stations, and terminal storage, were estimated from cost curves developed for other but similar studies. An allowance of 2 percent of identifiable costs was included for landscaping and environmental enhancement. Land acquisition costs for right-of-way were based on $75 per acre. Access roads, where necessary, were assumed to cost $20,000 per mile.

Indirect costs such as costs for all engineering studies, surveys, designs, specifications, exploration, testing, inspection, administration, etc., were estimated on a percentage of field costs depending on the magnitude and expected complexity of each plan. All costs were adjusted where necessary to the October 1970 price index of construction costs. All investment costs were escalated to 1975 to show cost of water at the two time frames.

Acquisition of Water Rights

The acquiring of a water right for use of water is included in storage costs or assigned costs of water from aqueducts. The one exception to this premise is in Colorado. No water source could be identified without impairment of uses already in effect. Accordingly, a water supply for the Watkins plant site was assumed procurable by purchasing sufficient irrigated acreage and the attendant water right to supply the needs of the steamplant. Such a right could be exercised under the principle of higher use, higher benefit doctrine.

Costs

Capital Costs

The field costs of conveyance facilities for each of the plans, all engineering, supervision, administration, and related indirect costs are summarized in Tables 3 and 3A. The October 1970 costs are escalated to 1975 by annual escalation rates of 5 percent per year compounded annually.

Interest During Construction

The construction period for each of the plans is shown in Tables 3 and 3A. It varies from 3 to 6 years. One year's period of time as a

Table 3.--Costs of Water

North Central Power Study

Plant Location	Plant Size (MW)	Construction Period (Years)	Cost Conveyance Facilities (Oct. 1970)	Escalation to 1975	Capital Costs	Interest During Construction	Total Capital Cost (1975)
			(- - - - - -	- - - - - -	$1,000 - - -	- - - - - -	- - - - - -)
North Dakota							
Bowman #1	5,000	3	$22,881	$ 6,315	$ 29,196	$ 1,517	$ 30,713
Bowman #2	5,000	6	101,305	27,960	129,265	13,429	142,694
N of Dickinson	3,000	3	24,219	6,684	30,903	1,605	32,508
Dickinson	3,000	4	35,609	9,828	45,437	3,147	48,584
Dickinson and	(3,000)	4	56,000	15,456	71,456	4,949	76,405
Bowman	(5,000)	4	55,471	15,310	70,781	4,902	75,683
Beulah	5,000	3	18,251	5,037	23,288	1,210	24,498
Center	1,000	3	6,615	1,826	8,441	438	8,879
South Dakota							
Ludlow	1,000	3	12,066	3,330	15,396	800	16,196
Colorado							
Watkins	1,000	3	8,086	2,232	10,318	536	10,854
Wyoming							
W of Kemmerer	5,000	4	33,660	9,290	42,950	2,975	45,925
NE of Rock Springs	1,000	3	13,129	3,624	16,753	870	17,623
N of Wamsutter	5,000	4	59,290	16,364	75,654	5,240	80,894
Gillette Vicinity, 10 Plants	10,000		(- - - - - - - -	Hardin	to Gillette	Aqueduct - - - - -	-)
Spotted Horse	3,000			" "	" "	"	
Lake DeSmet	10,000			" "	" "	"	

Table 3.—Costs of Water (continued)

North Central Power Study

Plant Location	Plant Size (MW)	Construction Period (Years)	Cost Conveyance Facilities (Oct. 1970)	Escalation to 1975	Capital Costs	Interest During Construction	Total Capital Cost (1975)
			(- - - - - - - -	- - - - - - - - -	$1,000 -	- - - - - - - - -	- - - - - -)
Montana							
NW of Brockway	5,000	4	$36,976	$10,205	$47,181	$3,268	$50,449
Paxton	1,000	4	12,637	3,488	16,125	1,117	17,242
Richey	1,000	4	13,779	3,803	17,582	1,218	18,800
Fort Kipp	1,000	2	1,300	359	1,659	57	1,716
Reserve	1,000	3	12,286	3,391	15,677	814	16,491
Coal Ridge	1,000	4	16,485	4,550	21,035	1,457	22,492
Wibaux	5,000	3	26,648	7,355	34,003	1,766	35,769
W of Savage	1,000	3	7,672	2,117	9,789	508	10,297
Colstrip	5,000	3	26,776	7,390	34,166	1,775	35,941
NW of Brandenburg	1,000	2	5,682	1,568	7,250	251	7,501
SE of Ashland	5,000	3	12,117	3,344	15,461	803	16,264
Birney	1,000						
Birney-PJ	1,000						
S of Birney	10,000	3	19,892	5,490	25,382	1,318	26,700
Kirby Alt. 1	1,000	3	9,074	2,504	11,578	601	12,179
Kirby Alt. 2	1,000	4	22,570	6,229	28,799	1,995	30,794
Decker	5,000						
Volborg	5,000	4	33,353	9,205	42,558	2,948	45,506
Camps Pass	10,000	4	84,153	23,226	107,379	7,437	114,816
Sonnette	1,000	2	8,321	2,297	10,618	368	10,986
Broadus	3,000						
Moorhead	5,000						

Table 3A.--Costs of Water

North Central Power Study
(Oct. 1970 Price Level)

Plant Location	Plant Size (MW)	Construction Period (Years)	Cost Conveyance Facilities (Oct. 1970)	Interest During Construction	Total Investment Cost
			(- - - - - - - - - -	- $1,000 - - - - -	- - - - - -)
North Dakota					
Bowman #1	5,000	3	$ 22,881	$ 1,189	$ 24,070
Bowman #2	5,000	6	101,305	10,525	111,830
N of Dickinson	3,000	3	24,219	1,258	25,477
Dickinson	3,000	4	35,609	2,466	38,075
Dickinson and	(3,000)	4	56,000	3,879	59,879
Bowman	(5,000)	4	55,471	3,842	59,313
Beulah	5,000	3	18,251	948	19,199
Center	1,000	3	6,615	344	6,959
South Dakota					
Ludlow	1,000	3	12,066	627	12,693
Colorado					
Watkins	1,000	3	8,086	420	8,506
Wyoming					
W of Kemmerer	5,000	4	33,660	2,331	35,991
NE of Rock Springs	1,000	3	13,129	682	13,811
N of Wamsutter	5,000	4	59,290	4,106	63,396
Gillette Vicinity,					
10 Plants	10,000 ea.		(- - - - Hardin to	Gillette Aqueduct	- -)
Spotted Horse	3,000		" " "	"	"
Lake DeSmet	10,000		" " "	"	"

Table 3A.--Costs of Water (continued)

North Central Power Study
(Oct. 1970 Price Level)

Plant Location	Plant Size (MW)	Construction Period (Years)	Cost Conveyance Facilities (Oct. 1970)	Interest During Construction	Total Investment Cost
			(- - - - - - - - - -	- $1,000 - - - - - -	- - - - -)
Montana					
NW of Brockway	5,000	4	$36,976	$2,561	$39,537
Paxton	1,000	4	12,637	875	13,512
Richey	1,000	4	13,779	954	14,733
Fort Kipp	1,000	2	1,300	45	1,345
Reserve	1,000	3	12,286	638	12,924
Coal Ridge	1,000	4	16,485	1,142	17,627
Wibaux	5,000	3	26,648	1,384	28,032
W of Savage	1,000	3	7,672	399	8,071
Colstrip	5,000	3	26,776	1,391	28,167
NW of Brandenburg	1,000	2	5,682	197	5,879
SE of Ashland	5,000	3	12,117	629	12,746
Birney	1,000		(- Plant located	adjacent to	Tongue River -)
Birney-PJ	1,000		" "	" "	" "
S of Birney	10,000	3	19,892	1,033	20,925
Kirby Alt. 1	1,000	3	9,074	471	9,545
Kirby Alt. 2	1,000	4	22,570	1,563	24,133
Decker	5,000		(- Plant located	adjacent to	Tongue River -)
Volborg	5,000	4	33,353	2,310	35,663
Camps Pass	10,000	4	84,153	5,828	89,981
Sonnette	1,000	2	8,321	288	8,609
Broadus	3,000		(- Plant located	adjacent to	Powder River -)
Moorhead	5,000		" "	" "	" "

minimum was assumed to be necessary for preconstruction activities for each plan for right-of-way acquisition, foundation exploration, preparation of design data, preparation of designs and specifications, call for bids, and award of contracts. The interest during construction was computed at 3.463 percent simple interest for one-half the capital costs for the full construction period.

Operation and Maintenance

The 85-percent load factor of the steamplants would require that operational and maintenance personnel be on the job throughout the year. Costs to operate and maintain the facilities were computed on this assumption and that each pumping plant would be semiattended. These costs are shown in Tables4 and 4A.

Replacements

The project life of each coal field was established at approximately 35 years by the ground rules for the overall North Central Power Study. On this premise no replacements would be required for any major component of the conveyance works with a life over 30 years. Experience has indicated that no replacements are necessary for Reclamation-built waterways, pipelines, reservoirs and surge facilities and that minor items that are replaced would be treated as maintenance costs. The facilities most likely to need replacements are certain items of the pumping plants. A pumping installation up to about 7,000 horsepower consists of cost components as follows:

Component	Percent of Overall Structure Costs (Percent)
Structures and improvements	55
Pumps and prime movers	27
Accessory electrical equipment	11
Miscellaneous equipment	2
Remote control equipment	5

Approximately 8.50 percent of the pumps and prime movers would require replacement after 20 years of operation and approximately 7.40 percent after 30 years. Also, about 7.50 percent of the accessory electrical

Table 4.--Annual Costs of Water

North Central Power Study
(1975 Costs)

Plant Location	Plant Size (MW)	Conveyance Investment 1/	Pumping Energy 2/	Replacements 3/	Operation & Maintenance	Assigned Aqueduct or Storage	Total	Per Ac.-Ft. Delivered (Dollars)
		(- - - -	- - - -	$1,000	- - - -	- - - -	- -)	
North Dakota								
Bowman #1	5,000	$1,528	$188	$ 61	$141	$1,925	$3,843	$ 70
Bowman #2	5,000	7,097	702	276	288	495	8,858	161
N of Dickinson	3,000	1,617	156	65	178	1,155	3,171	96
Dickinson	3,000	2,416	268	96	265	297	3,342	101
Dickinson and	(3,000)	3,800	600	151	323	792	5,666	64 4/
Bowman	(5,000)	3,764	312	148	257	--	4,481	145 5/
Beulah	5,000	1,218	112	47	29	495	1,901	35
Center	1,000	442	49	17	117	99	724	66
South Dakota								
Ludlow	1,000	806	72	32	160	385	1,455	132
Colorado								
Watkins	1,000	540	56	22	123	275	1,016	92
Wyoming								
W of Kemmerer	5,000	2,284	356	89	228	440	3,397	62
NE of Rock Springs	1,000	877	108	34	262	88	1,369	124
N of Wamsutter	5,000	4,024	448	158	331	440	5,401	98
Gillette Vicinity, 10 Plants	10,000 ea.	(- - - - - - - - - - - Hardin to Gillette Aqueduct - - - - - - - - -)						(101-121) 6/
Spotted Horse	3,000	" " " " "						(81-96) 6/
Lake DeSmet	10,000	" " " " "						(76-87) 6/

Table 4.--Annual Costs of Water (continued)

North Central Power Study
(1975 Costs)

Plant Location	Plant Size (MW)	Conveyance Investment[1/]	Pumping Energy[2/]	Replacements[3/]	Operation & Maintenance	Assigned Aqueduct or Storage	Total	Per Ac.-Ft. Delivered (Dollars)
		(- - - - - - -	- - - - - -	- - - $1,000 -	- - - - - -	- - - - - -	- -)	
Montana								
NW of Brockway	5,000	$2,509	$336	$ 98	$235	$ 495	$3,673	$ 67
Paxton	1,000	858	68	33	157	99	1,215	110
Richey	1,000	935	88	36	213	99	1,371	125
Fort Kipp	1,000	85	12	4	27	99	227	21
Reserve	1,000	820	68	33	188	99	1,208	110
Coal Ridge	1,000	1,119	96	43	247	99	1,604	146
Wibaux	5,000	1,779	280	71	205	495	2,830	51
W of Savage	1,000	512	60	20	124	99	815	74
Colstrip	5,000	1,788	312	71	189	495	2,855	52
NW of Brandenburg	1,000	373	40	15	89	99	616	56
SE of Ashland	5,000	809	76	32	75	1,870	2,862	52
Birney	1,000	(- - Plant located	adjacent to	Tongue River	- -)	374	374	34
Birney-PJ	1,000	" "	"	" "	"	374	374	34
S of Birney	10,000	1,328	212	52	88	5,500	7,180	65
Kirby Alt. 1	1,000	606	84	23	154	374	1,241	113
Kirby Alt. 2	1,000	1,532	40	60	94	374	2,100	191
Decker	5,000	(- - Plant located	adjacent to	Tongue River	- -)	1,870	1,870	34
Volborg	5,000	2,263	304	89	232	495	3,383	62
Camps Pass	10,000	5,711	912	226	374	990	8,213	75
Sonnette	1,000	546	80	22	151	319	1,118	102
Broadus	3,000	(- - Plant located	adjacent to	Powder River	- -)	957	957	29
Moorhead	5,000	" "	"	" "	"	1,595	1,595	29

1/ Investment costs amortized over 35 years @ 3.463 percent.
2/ Energy costs computed at 4 mills per kwh.
3/ Combined replacement factor = 0.00304 x field cost.
4/ Unit cost for 88,000 acre-feet of water delivered to Dickinson; 33,000 for Dickinson plant and 55,000 for Bowman plant.
5/ Includes $64 per acre-foot for water delivered to Dickinson for Bowman plant.
6/ Cost range for medium and large size aqueducts, see Table 6.

Table 4A.--Annual Costs of Water

North Central Power Study
(Oct. 1970 Price Level)

Plant Location	Plant Size (MW)	Conveyance Investment 1/	Pumping Energy 2/	Replacements 3/	Operation & Maintenance	Assigned Aqueduct or Storage	Total	Per Ac.-Ft. Delivered (Dollars)
		(- - - - - -	- - - - - -	- $1,000 -	- - - - - -	- - - - - -	- - -)	
North Dakota								
Bowman #1	5,000	$1,197	$188	$ 48	$141	$1,925	$3,499	$ 64
Bowman #2	5,000	5,562	702	216	288	495	7,263	132
N of Dickinson	3,000	1,267	156	51	178	1,155	2,807	85
Dickinson	3,000	1,894	268	75	265	297	2,799	85
Dickinson and	(3,000)	2,978	600	118	323	792	4,811	55 4/
Bowman	(5,000)	2,950	312	116	257	--	3,635	121 5/
Beulah	5,000	955	112	37	29	495	1,628	30
Center	1,000	346	49	13	117	99	624	57
South Dakota								
Ludlow	1,000	631	72	25	160	385	1,273	116
Colorado								
Watkins	1,000	423	56	17	123	275	894	81
Wyoming								
W of Kemmerer	5,000	1,790	356	70	228	440	2,884	52
NE of Rock Springs	1,000	687	108	27	262	88	1,172	106
N of Wamsutter	5,000	3,153	448	124	331	440	4,496	82
Gillette Vicinity, 10 Plants	10,000 ea.	(- - - - - - - - - - St. Xavier to Gillette Aqueduct - - - - - - - - -)						(85-101) 6/
Spotted Horse	3,000	" " " " "						(68-80) 6/
Lake DeSmet	10,000	" " " " "						(65-73) 6/

Table 4A.--Annual Costs of Water (continued)

North Central Power Study
(Oct. 1970 Price Level)

Plant Location	Plant Size (MW)	Conveyance Investment 1/	Pumping Energy 2/	Replacements 3/	Operation & Maintenance	Assigned Aqueduct or Storage	Total	Per Ac.-Ft. Delivered (Dollars)
		($1,000					)	
Montana								
NW of Brockway	5,000	$1,967	$336	$ 77	$235	$ 495	$3,110	$ 57
Paxton	1,000	672	68	26	157	99	1,022	93
Richey	1,000	733	88	28	213	99	1,161	106
Fort Kipp	1,000	67	12	3	27	99	208	19
Reserve	1,000	643	68	26	188	99	1,024	93
Coal Ridge	1,000	877	96	34	247	99	1,353	123
Wibaux	5,000	1,394	280	56	205	495	2,430	44
W of Savage	1,000	401	60	16	124	99	700	64
Colstrip	5,000	1,401	312	56	189	495	2,453	45
NW of Brandenburg	1,000	292	40	12	89	99	532	48
SE of Ashland	5,000	634	76	25	75	1,870	2,680	49
Birney	1,000	(- - Plant located adjacent to Tongue River - -)				374	374	34
Birney-PJ	1,000	" " " " " "				374	374	34
S of Birney	10,000	1,041	212	41	88	3,960	5,342	49
Kirby Alt. 1	1,000	475	84	18	154	374	1,105	100
Kirby Alt. 2	1,000	1,200	40	47	94	374	1,755	160
Decker	5,000	(- - Plant located adjacent to Tongue River - -)				1,870	1,870	34
Volborg	5,000	1,774	304	70	232	495	2,875	52
Camps Pass	10,000	4,476	912	177	374	990	6,929	63
Sonnette	1,000	428	80	17	151	319	995	90
Broadus	3,000	(- - Plant located adjacent to Powder River - -)				957	957	29
Moorhead	5,000	" " " " " "				1,595	1,595	29

1/ Investment costs amortized over 35 years @ 3.463 percent.
2/ Energy costs computed at 4 mills per kwh.
3/ Combined replacement factor = .002674 x field cost.
4/ Unit cost for 88,000 acre-feet of water delivered to Dickinson; 33,000 for Dickinson plant and 55,000 for Bowman plant.
5/ Includes $54 per acre-foot for water delivered to Dickinson for Bowman plant.
6/ Cost range for medium and large size aqueducts, see Table 6A.

equipment, not including transmission and transformation facilities, would need replacing after 15 years of operation. Miscellaneous mechanical equipment consists of 2 percent of a large pumping installation, and about 4.10 percent would require replacement after 25 years. Remote control equipment was assumed to be completely replaced once during the economic life of the water conveyance facilities.

When all of these factors are computed, assuming an interest rate of 3.463 percent per annum, a combined single factor of 0.002674 would be derived to estimate replacement costs at 1970 price level for a typical pumping installation. This factor when escalated to 0.00341 produces sinking fund amounts for the 1975 price level. Annual replacement costs for each plan and price level are summarized in Tables 4 and 4A.

Power and Energy Costs

The average plant horsepower installation and annual energy requirements are tabulated in Table 2 for each plan and the number of pumping plants. The derivation of horsepower installation and energy is based on 80-percent pumping plant efficiency. The $0.004 cost per kilowatt-hour is the cost of energy delivered to load center. Transmission losses were assumed to be 8 percent of the load, and the $0.004 cost per kilowatt-hour included capital investment, operation and maintenance of transmission facilities from load center to pumping plant. The cost of pumping energy is shown in Tables 4 and 4A.

Financial Analysis

Annual costs per acre-foot of water delivered to each site as derived in Tables 4 and 4A are of sufficient magnitude to recover all investment, operation, maintenance, replacement, and assigned aqueduct or storage costs. Investment costs are amortized at a rate of 3.463 percent interest over a 35-year repayment period except for assigned aqueduct or storage costs which were estimated using a 50-year repayment period.

The electric-steamplant for each site was sized to use the known recoverable coal reserves in approximately a 35-year period, which, in turn, limited the amortization period and plant life to 35 years.

Investments in large storage reservoirs or large aqueducts with capabilities to deliver water to multiple or alternative points of use are amortized over a 50-year period. The useful life of storage and aqueduct facilities is therefore not limited by the recoverable coal reserves and plant life at any one particular site. For instance, the proposed Hardin to Gillette Aqueduct would not have the capacity to deliver water to all ten potential 10,000-megawatt plants in the Gillette vicinity and/or other sites along the system simultaneously; however, the aqueduct would have a useful life sufficient for two or three successive 35-year periods of plant operation.

The repayment rate (3.463 percent) used in this analysis is the rate applicable for fiscal year 1971 under provisions of the Water Supply Act of 1958 (P.L. 500, 85th Cong.), as amended. Although the actual rate applicable to each conveyance facility would be the rate in effect during the fiscal year in which construction begins, the use of the current rate is considered adequate for comparative water cost purposes. The relative cost of water delivery will remain the same between potential plant sites although the spread between costs will widen if the repayment rate increases. The financial arrangements considered in this analysis are based on Bureau of Reclamation repayment criteria.

These costs are relative and adequate for plan selection.

Other Considerations

Plants Adjacent to Streams

All steamplants that could be located adjacent to streams would not require expensive and complex conveyance systems. Facilities for such plants were assumed to be constructed as a part of the steamplant, and financing costs would therefore bear a different rate of interest. The only additional costs that may occur would be storage costs of water.

Assigned Aqueduct or Storage Costs

This item represents the costs of developing or acquiring a firm water supply whether from an existing reservoir, new reservoir to be constructed, or buying land with a water right. The cost of acquiring a water right or buying water on a firm basis is listed in Table 5. The estimated storage cost, cost to acquire a right, or aqueduct cost are listed in Table 5 for each plan. The total annual aqueduct or storage cost for each site is included in Tables 4 and 4A.

The costs and other pertinent data summarized in Tables 6 and 6A have been compiled from these studies. The data have been adjusted to an October 1970 price base, and to the 1975 price level by escalating 1970 prices to 1975. The annual cost of water deliveries for the aqueducts running from Hardin on the Bighorn River to Gillette, Wyoming, are based on three sizes of conduits. Each conduit size, along the same route site, would deliver a smaller or larger quantity of water. The cost per acre-foot of water delivered through each of the four reaches or branch line would depend on the combination of conduit size. The costs summarized in Tables 4 and 4A for the Spotted Horse site, the 10 plants in Gillette vicinity, and the Lake DeSmet site show a range of costs depending on whether water would be delivered through a medium size conduit or large size conduit to Gillette.

Table 5.--Cost of Storage Water and Aqueducts

North Central Power Study

Plant Location	Water Source	Annual Water Delivery (A.F.)	Estimated Annual Cost per Acre-foot
North Dakota			
Bowman #1	Little Missouri River	55,000	$35
Bowman #2	Garrison Reservoir	55,000	9
N of Dickinson	Little Missouri River	33,000	35
Dickinson	Garrison Reservoir	33,000	9
Dickinson and Bowman	Garrison Reservoir	88,000	9
Beulah	Missouri River	55,000	9
Center	" "	11,000	9
South Dakota			
Ludlow	Little Missouri River	11,000	35
Colorado			
Watkins	South Platte River	11,000	25
Wyoming			
W of Kemmerer	Green River	55,000	8
NE of Rock Springs	" "	11,000	8
N of Wamsutter	" "	55,000	8
Gillette Vicinity, 10 plants	Bighorn River (Aqueduct)	110,000 ea.	(96-114)
Spotted Horse	" " "	33,000	(76-90)
Lake DeSmet	" " "	110,000	(73-82)
Montana			
NW of Brockway	Missouri River	55,000	9
Paxton	" "	11,000	9
Richey	" "	11,000	9
Fort Kipp	" "	11,000	9
Reserve	" "	11,000	9
Coal Ridge	" "	11,000	9
Wibaux	Yellowstone River	55,000	9
W of Savage	" "	11,000	9
Colstrip	" "	55,000	9
NW of Brandenburg	" "	11,000	9
SE of Ashland	Tongue River	55,000	34
Birney	" "	11,000	34
Birney-PJ	" "	11,000	34
S of Birney	Tongue River Reservoir	60,000	(34) 38
	Bighorn River (Aqueduct)	50,000	(42)
Kirby Alt. 1	Tongue River	11,000	34
Kirby Alt. 2	" "	11,000	34
Decker	" "	55,000	34
Volborg	Yellowstone River	55,000	9
Camps Pass	" "	11,000	9
Sonnette	Powder River	11,000	29
Broadus	" "	33,000	29
Moorhead	" "	55,000	29

Table 6.--Aqueducts - Hardin to Gillette

Annual Cost of Water Deliveries 1/
(1975 Cost)

North Central Power Study

REACH I	Hardin to Six Mile Creek		
Aqueduct size	72 inch	108 inch	144 inch
Annual cost per acre-foot	$48.50	$34.50	$28.40
REACH II	Six Mile Creek to Tongue River (Acme)		
Aqueduct size	60 inch	90 inch	120 inch
Annual cost per acre-foot	$6.00	$4.10	$3.50
REACH III	Tongue River (Acme) to Clear Creek Divide (Ulm)		
Aqueduct size	48 inch	90 inch	120 inch
Annual cost per acre-foot	$50.90	$22.70	$19.10
REACH IV	Clear Creek Divide (Ulm) to Gillette		
Aqueduct size	48 inch	78 inch	108 inch
Annual cost per acre-foot	$75.20	$50.80	$41.30
BRANCH LINE	Clear Creek Divide (Ulm) to Lake DeSmet		
Aqueduct size		60 inch	
Annual cost per acre-foot		$16.40	

1/ Annual costs per acre-foot based on 3.463 percent interest rate and 50-year amortization period. Basic water charge of $9 per acre-foot from Bighorn Lake must be added at any delivery point to derive total annual cost of water.

Table 6A.--Aqueducts - Hardin to Gillette

Annual Cost of Water Deliveries 1/

North Central Power Study

REACH I	Hardin to Six Mile Creek		
Aqueduct size	72 inch	108 inch	144 inch
Annual cost per acre-foot	$40.70	$29.20	$24.30
REACH II	Six Mile Creek to Tongue River (Acme)		
Aqueduct size	60 inch	90 inch	120 inch
Annual cost per acre-foot	$5.00	$3.40	$2.80
REACH III	Tongue River (Acme) to Clear Creek Divide (Ulm)		
Aqueduct size	48 inch	90 inch	120 inch
Annual cost per acre-foot	$42.40	$19.00	$16.00
REACH IV	Clear Creek Divide (Ulm) to Gillette		
Aqueduct size	48 inch	78 inch	108 inch
Annual cost per acre-foot	$61.20	$41.40	$33.70
BRANCH LINE	Clear Creek Divide (Ulm) to Lake DeSmet		
Aqueduct size		60 inch	
Annual cost per acre-foot		$13.40	

1/ Annual costs per acre-foot based on July 1970 price levels, 3.463 percent interest rate, and 50-year amortization period. Basic water charge of $9 per acre-foot from Bighorn Lake must be added at any delivery point to derive total annual cost of water.

Addendum

Subsequent to completion of the cost study to determine the relative cost of water delivered to each of the identified coal reserves, a question arose as to the adequacy of the quantity of water estimated for a 1,000 megawatt steam-electric generating plant. The method of computing water requirements was parallel to that employed for the Comprehensive Framework Study of the Missouri River Basin.

The investigators participating in the National Power Survey utilized different consumptive use for various types of cooling for fossil-fueled steamplants. A consumptive use including boiler make-up water of 28 c.f.s. per 1,000 megawatt installed capacity was used during that survey.

A reanalysis of unit water requirements and costs using 28 c.f.s. per 1,000 megawatt would greatly increase the water requirements but decrease the unit cost per acre-foot of water delivered. The revised water requirements and unit cost of water are tabulated on Table 7 and Table 8 for water delivered in Gillette, Wyoming, and Colstrip, Montana.

The latter three columns of each table list the unit cost of water when sharing the use of a pipeline conveyance system. It should be noted that the unit cost of water is less when the conveyance system is shared. As an example, in Table 7 the unit cost of water delivered in Gillette is considerably less for a 3,000 megawatt plant when the portion of water delivered to the steamplant is 67 percent of the total capacity of the conveyance system. The unit cost of water is even less when 33 percent of the total capacity of the pipeline is for a 3,000-megawatt steamplant.

It is to be noted that about 1,000,000 acre-feet delivery to Gillette from the Bighorn River at Hardin, Montana, is about the limit of the water supply at this point. About 500,000 acre-feet would be divertible from the Yellowstone River through a second pipeline system running from Miles City, Montana, to Gillette, Wyoming. However, total potential annual supplies in the Gillette-Colstrip area are estimated to be 1.8 million acre-feet. Accordingly, the unit cost of water through the second pipeline would not be at the same rate. The unit costs of water listed on Tables 7 and 8 include the two water costs.

Table 7.--Unit Cost of Water Delivered in Gillette Area

North Central Power Study
(Oct. 1970 Price Level)

Aqueduct Water Deliveries and Unit Costs

MW Installed	Water for Generation A.F./Yr.1/	Unit Cost of Generation Water (Generation Portion of Delivered Water) 100%	67%	50%	33%
3,000	50,000	$170.00	$149.00	$133.00	$114.00
6,000	103,000	133.00	113.00	102.00	91.00
8,000	137,000	118.00	102.00	94.00	85.00
13,000	212,000	101.00	90.00	85.00	79.00
15,000	257,000	96.00	86.00	82.00	78.00
20,000	342,000	89.00	82.00	79.00	77.00
23,000	394,000	86.00	80.00	78.00	76.50
25,000	427,000	84.00	79.00	77.00	76.00
30,000	510,000	82.00	78.00	76.50	76.00
40,000	685,000	79.00	76.50	76.00	76.00
50,000	855,000	77.00	76.00	76.00	76.00

1/ Based on 28 c.f.s. per 1,000 MW installed capacity as suggested in Chapter X of National Power Survey.

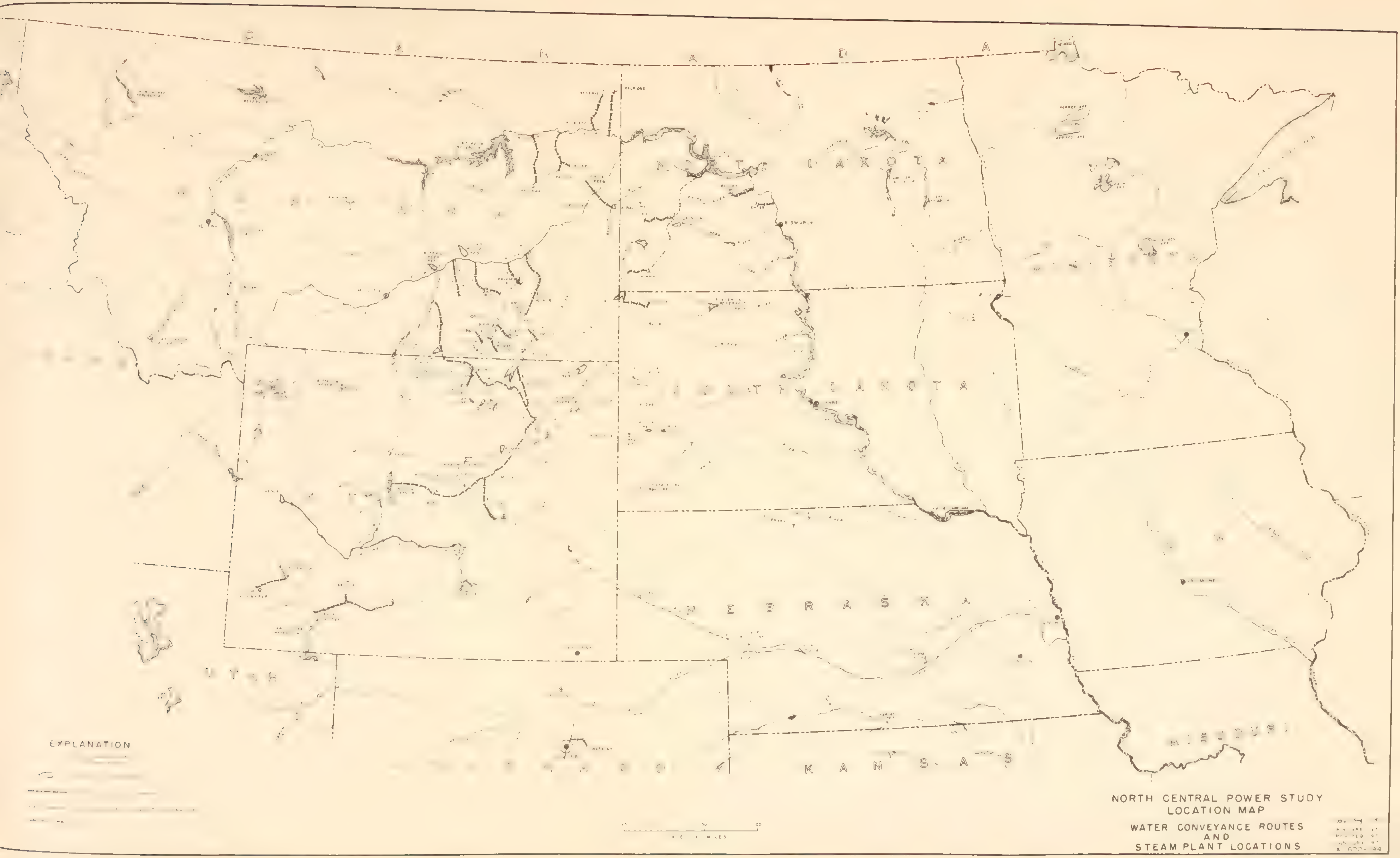
Table 8.--Unit Cost of Water Delivered in Colstrip Area

North Central Power Study
(Oct. 1970 Price Level)

Aqueduct Water Deliveries and Unit Costs

MW Installed	Water for Generation A.F./Yr.[1]	Unit Cost of Generation Water (Generation Portion of Delivered Water) 100%	67%	50%	33%
3,000	50,000	$45.00	$41.00	$37.00	$32.00
6,000	103,000	37.00	31.00	28.00	23.00
8,000	137,000	33.00	28.00	24.00	20.00
13,000	212,000	27.00	22.00	20.00	18.00
15,000	257,000	25.00	21.00	19.00	16.50
20,000	342,000	22.00	19.00	17.00	16.00
23,000	394,000	21.00	18.00	16.00	15.50
25,000	427,000	20.00	17.00	15.50	15.00
30,000	510,000	19.00	16.00	15.00	15.00
40,000	685,000	17.00	15.50	15.00	15.00
50,000	855,000	16.00	15.00	15.00	15.00

1 Based on [illegible] c.f.s. per 1,000 MW installed capacity as suggested in Chapter X of National Power Survey.


NORTH DAKOTA
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X. LAND RECLAMATION

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General Comments

Brief Summary of Mined Land Reclamation By State

Mined Land Reclamation

- Montana
- North Dakota
- Wyoming
- Arizona
- Colorado, Idaho, Nevada, New Mexico, South Dakota, Utah

Pipeline Right-of-Way Reclamation

Exhibit "A"

Exhibit "B"

Exhibit "C"

GENERAL COMMENTS

It is necessary to make this report very general in scope since the specific areas of concern have not been localized. Nevertheless, the basic problems and cost of reclamation will not vary greatly within any given state. This report is divided into two major sections: mined land reclamation and pipeline right-of-way reclamation.

Basically, the reclamation of strip mined land throughout the area of the North Central Power Study must be kept simple using native varieties common to the area and which are able to regenerate and maintain themselves without constant care. More and more the mining companies must lead the way in determining a use for the mined areas and then must follow through with reclamation to achieve that usage.

One additional study is attached to this report. In order to determine the dollar cost of reclamation per ton of coal mined one need only determine the tons of coal to be mined per acre and the dollar cost of reclamation per acre. The latter can then be taken from Exhibit "A". Exhibit "B" provides a ready chart for reading the dollar cost of reclamation per ton of coal mined when any operator in any given area has determined the two unknowns mentioned above.

Right-of-way reclamation poses no unusual problems. As reflected in the detailed report of the Land Reclamation Task Force, rights-of-way can be reclaimed adequately for $18 to $35 per acre, including leveling, soil preparation, fertilizing and seeding.

MONTANA

The coal reserves for surface mining are located mainly in Eastern Montana. Reclamation of this area has proven costly because of the heavy overburden and climatic conditions. Natural restoration of vegetation does not readily occur here.

The Montana Agricultural Experiment Station has conducted reclamation experiments at Colstrip including use of tubed seedlings, plastic moisture catch basins, fertilizer programs, and comparison of various trees, shrubs and grasses.

Knife River Coal Mining Company reclamation at Savage started in 1965. The spoils support vegetation, primarily grasses. Reclamation costs range to a maximum of $500 per acre when leveling these spoils to slopes of 25% or less. Restoration generally is successful on the first attempt. The Soil Conservation Service has also become involved in reclamation studies.

The reclamation law requires a reclamation contract between the state and the operator with generally stringent requirements to return lands to their highest potential usage. The operator can receive a partial refund of coal mine license tax for reclamation work completed.

NORTH DAKOTA

North Dakota's coal reserves occur in the western half of the state. The rainfall in this area varies from 13" in the west to 15" in the east. Spoils are not toxic and runoff is minimal, so adjacent areas and waters are not affected. Reclamation costs probably average about $350, but vary from $120 to $500 per acre depending on the amount of dirt work required. Over a long period of time many of the older mines have become naturally re-vegetated.

The North Dakota law as amended in 1971 is one of the most stringent reclamation laws in the US. Any operator engaged in surface mining with overburdens exceeding 10 feet must obtain a permit. The bond fee for this permit is based on acreage disturbed. The operator must obtain approval of its reclamation plan and submit annual reports. Lands must be restored to best usage, i.e. forestry, grazing, croplands, haylands, wildlife habitat, recreation, etc. Various degrees of leveling are required according to planned usage.

WYOMING

The semi-arid conditions throughout the coal regions make reclamation most difficult. Reclamation to date has had mixed results with success in some areas in establishing grasses and other vegetation. Irrigation is very limited; however it has been demonstrated that the soil materials in the spoils will support an adequate cover with proper fertilization and seeding. Spoils in Wyoming are not toxic and mined areas are self contained.

Most of Wyoming's mining is remote from population centers and located on low value land. Little earth moving has been required in the past and spoils such as at Glenrock require no earth work because of the method of mining. Reclamation costs may vary from less than \$100 to nearly \$500 per acre. (See Exhibit "A")

The Wyoming reclamation laws are less exacting than most other states. Spoils must be graded to a rolling topography with water impoundment where possible and protection of adjacent areas and water from toxic materials, siltation, etc.

ARIZONA

Peabody Coal Company's operations at Black Mesa are encountering overburden of almost zero to about 120 feet. They mine about 400 acres per year, under a lease requiring the lands be reclaimed to a condition as good as that when received. Arid conditions make reclamation difficult. This is a new mine and data is scarce, but costs should compare closely to Wyoming. Native grasses including indian rice grass and blue grama are being used. Legumes are included to add nitrogen to the soil.

COLORADO, IDAHO, NEVADA, NEW MEXICO, SOUTH DAKOTA, UTAH

This Task Force does not at the present time contemplate that the study underway will result in consideration of a site in any one of these states for a major power generating complex. While substantial coal or lignite reserves do exist in these states it is generally believed that the reserves and conditions in other states covered by this study are vastly superior.

MINED LAND RECLAMATION

MONTANA

1. Coal Reserves: Eastern Montana has the greatest potential for surface mining. This area includes lignite reserves in the extreme eastern part of the state, coal reserves in the north end of the Powder River Basin including the Decker, Colstrip and Sarpy Creek areas and also the coal deposits near Roundup. The Montana School of Mines expects that no more than 120,000 acres in these areas will be mined in the next 50 years.

2. Results of No Reclamation: The results of no reclamation can be seen in the Colstrip mines southeast of Forsyth. The dry climate has resulted in minor erosion. The mines are self contained and no drainage or siltation leaves the mine area. Natural vegetative cover has become established but natural restoration of vegetation is slow and cannot be relied on by the operators. In the eastern counties where the rainfall is slightly higher and the overburden consists of slightly better soil materials, aerial borne seeds do result in cottonwood trees becoming established in the draws, and many of the range grasses and weeds become naturally established. A substantial cover of natural vegetation requires a period of 20 years or more.

3. Results of Reclamation: The Agricultural Experiment Station has been experimenting at Colstrip with old and new overburden piles. Their studies have been very productive in identifying procedures and species for reclaiming spoils. Studies on methods of fertilization, ground water conditions, windbreaks and use of various herbaceous plantings are bearing results. Knife River Coal Mining Company has also undertaken reclamation projects in the Savage, Montana area since 1965. It has been adequately demonstrated that overburden piles in

Montana are not toxic and do not result in toxic discharge. The spoils consist of materials that can support vegetation. Each year Knife River Coal is leveling or capping at least as much acreage as mined and the areas are then fertilized and seeded using farm equipment with results ranging from fair to good. Establishment of trees is a more difficult task and with the exception of establishing a limited number of species in the lower draws, the method of reclamation will primarily be grass and prairie cover. Even in areas relatively remote and of marginal agricultural value, public awareness and pressure indicates the necessity of undertaking reclamation costing many times over the actual land values in the area.

4. Cost by Type of Reclamation: With overburden greater than 50 feet experience has indicated that the cost of leveling to slopes of 25% or less could be as much as $500 per acre. Capping of spoils costs as little as 1/3 this amount. The first cost of fertilizing and seeding will be $25 to $50 per acre with possibly some additional fertilizer expense in subsequent years. Seeding by airplane without previous ground preparation has resulted in only spotty success and this practice has been discontinued by Knife River Coal.

5. Research and Possible New Methods of Reclamation: The Montana Agricultural Experiment Station has been experimenting with tubed seedlings, plastic moisture catch basins, windbreaks, shrubs, and varied methods of planting various grasses with different fertilizer treatments. Their program includes each of the areas of the state being mined, and projects involve every company mining in the state. Refinement of reclamation methods will undoubtedly follow this experimental work and better restoration of most mined areas should result. It is not expected however that the present reclamation techniques used in the Savage area will be greatly changed thereby.

6. Legal Aspects of Reclamation: Montana has had a mined land reclamation law since 1967. The law which was passed in 1967 provided for a voluntary agreement

between the state and individual operators. This agreement provides for reclamation of mined lands in accordance with their highest potential use.

During the 1969 session of the legislature another reclamation law was passed applicable only to those coal mining companies who had not entered into a voluntary agreement with the state. This law was a watered down version of the North Dakota and Illinois laws.

The 1971 session of the Montana legislature rescinded the 1967 and 1969 laws and passed a new law covering <u>all</u> surface mining in the state. The new law is flexible, requiring a reclamation contract between the state and the operator before mining can commence. Said contract will consider local conditions, potential land usage, and the advice of an "advisory committee" made up of seven state agencies, in determining required reclamation procedures. Reclamation will be done under bond. As an incentive to the operator he may receive a refund for the cost of reclamation up to a maximum of one cent per ton of the annual license tax presently being paid to the State of Montana. Said license tax is a sliding scale tax varying from four cents to ten cents per ton based on the Btu content of the coal. The law seems to be reasonable and well conceived, and should cause no undue problems for conscientious coal operators.

<u>NORTH DAKOTA</u>

<u>1. Coal Reserves</u>: The coal reserves in North Dakota occur in the western half of the state where there are more than a billion tons of strippable reserves. This coal underlies lands, including badlands, in the western part of the state and the great plains to the east.

<u>2. Results of No Reclamation</u>: In those mines 20 years old or older natural restoration has resulted in very substantial grasses and vegetative cover. Several of the older mines have substantial material value today as wildlife habitats

and recreation areas, and if permitted would provide excellent grazing. In fact the front cover of this report includes two pictures of a lake and grasslands in a mine naturally restored.

3. Results of Reclamation: The mines in North Dakota are self contained. No erosion affects adjacent lands. The overburden piles are devoid of excessive toxic materials and do not contribute either acid materials or sedimentation to local water bodies or lands. The spoils are composed of soil materials capable of supporting plant life. Whether planted to trees or range grasses, and whether leveled or left in their undisturbed state the overburden piles have proven receptive to reclamation efforts. An exception to this is the damage caused in a few locations by leveling and compacting spoils which are heavy in clay content.

4. Cost By Type of Reclamation: Exhibit A applies to all except a few of the small farmer type coal mines in the state. Reclamation costs range from about $120 per acre where trees are planted on raw overburden piles to about $500 where overburden is leveled to a rolling terrain and planted to grass and trees.

Leveling overburden piles "flat" has not proven to always be a good solution in North Dakota and the only operator following this procedure has been unable to show any good results in re-establishing vegetation after so leveling. Nevertheless, increased leveling or rolling of spoils will be required in the future and it is therefore necessary that the cost of reclaiming mined lands including some leveling and planting be estimated at about $200 to $500 per acre.

5. Research and Possible New Methods of Reclamation: Substantial studies and research has been conducted in North Dakota for the past several years including University guided studies. Some of the present methods of reclamation are based thereon. While new methods and procedures are constantly being tried,

this Task Force does not anticipate any substantial changes in method, expense or requirements in North Dakota.

6. Legal Aspects of Reclamation: The North Dakota law as amended in 1971, probably the third toughest reclamation law in the United States, is generally patterned after the Illinois Act. The law requires mining operators to present a plan of reclamation to the state. After surface mining operations are completed the operator must carry out reclamation of mined lands to provide any one of a number of uses including forestry, grazing lands, croplands, wildlife habitats, recreational areas, or home or industrial sites.

In order to accomplish this it has become unlawful for any operator to engage in surface mining if the overburden exceeds 10 feet without first obtaining a permit. This permit can be obtained from the Public Service Commission (State Mine Inspector) by posting a bond and paying a fee as follows: Ten acres or less: $25.00 plus $7.50 additional per acre between 2-10 acres. Ten to 50 acres: $100.00 plus $3.50 additional per acre for each acre between 11-50 acres. Fifty acres or more: $275.00 plus $2.50 additional per acre for each acre over 50 acres.

The purpose of the fees is to provide funds to administer this law. Regarding reclamation under this law each operator must meet the following requirements:
(1) All spoils within 660 feet of any public road, public building or cemetary must be graded to a rolling topography traversable by farm machinery, with slopes no greater than 20% unless the original grade was greater.
(2) Operator must, where possible, assist in impounding water for lakes or ponds by constructing the necessary dams.
(3) When lands are to be planted to trees, adequate access roads must be constructed.
(4) Lands to be used for pasture or forestry must have the peaks or ridges of the overburden piles "struck" off to a minimum width of 35 feet at the top.

(5) Lands to be used for hay must have the peaks and ridges graded to a slope not exceeding 20%, and the lands must be traversable by farm machinery.

(6) Adjacent property owners are protected by regulation that controls how close mining can take place next to property lines.

In order to control reclamation the operator must file annual reports and must also prepare reclamation plans for approval of the Commission. The Commission will base its approval upon the advice and technical assistance of the State Soil Conservation Commission, State Game & Fish Department, the State Forester and other agencies. It is then the operator's responsibility to carry out the reclamation and, when this has been completed to the satisfaction of the Commission, the bonds are released.

WYOMING

1. Coal Reserves: The coal regions of Wyoming are quite well defined and it is probable that the committee dealing with coal reserves will pinpoint the Powder River Basin as the primary source of coal reserves with emphasis on the area north of the Glenrock Field, Lake SeSmet, the Gilette area and the substantial coal deposits of the Colstrip and Decker, Montana area. The Hanna area of south-central Wyoming, the Red Desert, the Kemmerer area of southwest Wyoming are also areas of great potential.

2. Results of No Reclamation: The semi-arid conditions experienced in every locale of strippable coal reserves in Wyoming makes the revegetation phase of reclamation a difficult problem. Nevertheless the corresponding absence of toxic materials and the fact that the overburden materials are generally in and of themselves soil materials helps greatly in the reclamation. If no reclamation is practiced, mined areas in Wyoming will gradually over a period of tens of years establish a light range cover of sage and drouth tolerant grasses. In those areas observed the cover is not impressive at all but is comparable to the adjacent virgin

prairie.

3. Results of Reclamation: A number of reclamation projects have been undertaken in the coal fields of Wyoming with mixed results due to the variety of problems within the state. In the coal mines near Sheridan, Wyoming the Big Horn Coal Company has had substantial success in establishing grass and some trees. Their success is attributed to several factors including their method of stripping which results in a low, flat to gently rolling terrain, application of fertilizer, plus irrigation of the areas planted. This type of project is commendable. It must be recognized however that areas where such water is available for irrigation are limited and generally speaking reclamation must be directed towards self-sustaining types of cover.

In the Glenrock Field, Pacific Power and Light has undertaken reclamation on the gently rolling terrain left after their mining and has established prairie grass and cover with varying degrees of success. Their success has indicated that the overburden remaining after mining does constitute a soil material that can with proper fertilization and some moisture again develop a prairie cover. Their method of mining results in no peaks or ridges in the overburden. Depth of overburden averages about 37 feet and consists of loosly consolidated sandstone at the top 12 feet and about 25 feet of sandy clay.

Since 1965 about 250 acres at Glenrock have been reclaimed to grass covered prairie, using cereal rye, standard crested wheat grass and alfalfa or sweet clover. In 1970 Nordan crested wheat grass was added to their seed mixture. Fertilizer has been used at the time of seeding.

Their cost of seeding and fertilizing has been approximately $23 per acre.

Hanna field conditions are more desperate and the only attempts to revegetate that have met with substantial success have been those that include irrigation. As soon as the irrigation is discontinued almost everything that has been started dies. Obviously the coal companies cannot be expected to irrigate ad infinitum and the adjacent unmined terrain bears testimony to the futulity of trying to establish substantial vegetation in this part of the state.

Experimentation by the University of Wyoming on overburden piles remaining after mining in the Kemmerer area have met with some success and some species of grass and vegetation have shown the capacity to adapt to the new conditions. Use of impounded water for irrigation and stock water has been beneficial. Nevertheless the weather and other conditions in this area make the task difficult at best even on lands that have not been disturbed by mining.

4. Cost By Type of Reclamation: Very little substantial earth work other than that necessary in the process of mining has been undertaken in the mined areas of Wyoming. In some mines the method of mining makes subsequent earth work unnecessary. In those parts of the state where leveling or partial leveling of the overburden piles will be required the cost per acre can be expected to generally follow the study attached hereto as Exhibit A.

Overburden piles in the Kemmerer area and southern Powder River Basin will tend to be much lower and uniform than those in the Hanna Field and resulting earth work will be minimal. Tree planting will be minimal and it is probably fair to anticipate $25 to $50 per acre for preliminary fertilization and planting of grasses and legumes, with possibly some additional fertilization in subsequent years until vegetation becomes established.

5. Research and Possible New Methods of Reclamation: The University of Wyoming has been conducting research as have some other states, and it is possible that hydroseeding may prove to have some benefit in local applications. Basically

the climate and growing conditions are so unfriendly in each of the Wyoming mining areas that this committee does not at the present time forsee a break-through that will revolutionize the methods of reclaiming mined lands.

It seems obvious that the approach to reclamation in Wyoming must be kept simple. There are numerous ways to attain vegetative cover in even the most severe locales by using complex or exotic methods. Such methods are not only expensive, but temporary unless constantly maintained. Vegetation in mined areas must eventually maintain itself without constant care--hence reclamation must be kept simple.

6. Legal Aspects of Reclamation: Much of the mining in Wyoming is in areas remote enough from population centers that it does not receive the same notoriety as do strip mines in some other states. Nevertheless the environmental pressures are having their effect. As an industry we must even do some leveling where no truly beneficial results seem obvious. There is increased sympathy for the principle of leveling just to make an area flat even though the lands have questionable usefullness after leveling. The land values in areas mined in Wyoming are generally quite low and usually were marginal grazing lands to begin with. The tendency in the State of Wyoming seems to be to keep reclamation laws less exacting than in such states as Montana and North Dakota but in any long range planning the reclamation costs should contemplate maximum reclamation. Accordingly costs of $25 per acre for the most elementary reclamation program as at Glenrock to costs of over $500 per acre where substantial leveling is required should be anticipated.

The Wyoming mined land reclamation law requires operators of open cut mines to grade the overburden piles to reduce peaks and ridges to a rolling topography. Other requirements include construction of dams where lakes can be formed, adequate covering of any materials that could generate acid, encouragement of revegetation of lands, and filing of leases, maps and reports by the operators to show lands reclaimed.

Actually the requirement to grade all mined lands to reduce all peaks and ridges to a rolling topography could constitute in a sense a more rigid requirement than that in the North Dakota bill.

ARIZONA

1. Coal Reserves: Arizona coal production in the past has been minimal. This has been changed by Peabody Coal Company's operations on the Black Mesa. At Black Mesa coal can be strip mined with overburden ranging from almost zero to approximately 120 feet. The coal is bituminous and reserves underlie approximately 14,000 acres. Peabody expects to mine an average of 400 acres per year. While Peabody will be mining upwards of 13 million tons annually, the estimates are not currently available on the available coal that can be strip mined at Black Mesa. The Mesa has a perimeter of approximately 180 miles and the terrain is quite rough. Availability of water is a problem. The climate is arid and surface runoff is intermittent.

2. Reclamation: The arid conditions of the area makes any reclamation difficult. Peabody is required under its lease to return Black Mesa to the tribes in "as good condition as received, except for ordinary wear, tear and depletion incident to mining operations." Accordingly Peabody grades the surface so that contours blend with the surrounding land, after which native vegetation is planted. This is a new mine and little historical data is available. Costs of leveling and planting vegetation should closely approximate costs of similar operations in Wyoming. Restoration work follows closely behind the mining operations. Peabody reclamationists are using such native grasses as indian rice grass and blue grama. Peabody is also including legumes in their reseeding operation to add nitrogen to the soil.

COLORADO, IDAHO, NEVADA, NEW MEXICO, SOUTH DAKOTA, UTAH

This Task Force does not at the present time contemplate that the study underway will result in consideration of a site in any one of these states for a major power generating complex. While substantial coal or lignite reserves do exist in these states it is generally believed that the reserves and conditions in other states covered by this study are vastly superior. In Utah, for instance, coal reserves are estimated at more than 27 billion tons in about 20 fields, most of which is too deep for strip mining. Nevertheless, should adequate reserves prove to be available in any of these states it is believed that the requirements for reclamation and the cost thereof as well as the general procedures for accomplishing same will be comparable to or less than experience we now have in the states of North Dakota, Montana and Wyoming. Copies of state laws governing mined land reclamation in these states are not included in this report, but are available from this committee on request.

PIPELINE RIGHT-OF-WAY RECLAMATION

The problem of pipeline right-of-way reclamation is very minor compared to mined land reclamation because the disturbance of the surface is relatively minor. Toxic materials or materials incapable of plant growth are seldom brought to the surface unless they are already at the surface. When farm lands are crossed farmers often prefer that no vegetation be re-established. Experience has usually proven the right-of-way over farm lands to be equally productive to the adjacent lands by the next season after pipeline construction. In the case of grazing lands or federal and state lands it is often necessary to seed after grading the right-of-way.

At the time of pipeline construction the equipment used in backfilling the ditch can generally adequately compact the backfill material with little or no additional expense. If the topsoil cover is particularly desirable and worthy of saving, this can generally be done by the simple procedure of "double ditching". This procedure requires that a dozer or motor patrol make the first pass along the right-of-way area pushing the topsoil to one side with the ditcher then making the second pass to reach total depth for the ditch. Materials thus removed are replaced in reverse order resulting in the topsoil being replaced in the same position from which it was removed.

Treatment of the right-of-way after the ditch has been backfilled requires normal farm equipment to prepare the soil and plant the desirable ground cover including trees or brush where applicable, to blend with existing conditions. The probable expenses for reclaiming lands which are thus replanted should not exceed $35 to $50 per acre, and realistically may be closer to $25 per acre. There will of course be damages to settle on private lands as is the experience in any pipeline or any construction on private lands.

EXHIBIT "A"

LEVELING OVERBURDEN PILES TO A PREDETERMINED GRADE

Introduction

Some groups feel overburden piles should not be leveled and that these areas should be forested and game habitates created. Other groups advocate the partial or complete leveling of overburden piles. When there is a discussion concerning the partial or complete leveling of overburden areas, different costs are stated. This report will attempt to accurately calculate the amount of overburden to be moved and the cost of moving this overburden when either complete or partial leveling of these overburden piles are attempted.

When legislation concerning rehabilitation of overburden piles is discussed, one phrase continually crops up and this is "leveled to a gentle rolling topography". The lignite operators feel this phrase can not be defined. Therefore, any legislation which requires leveling should stipulate the minimum grade which is to be attained.

General Background

When calculating the cubic yards of overburden that is to be moved when leveling overburden piles to a predetermined grade, the following factors have to be taken into consideration:

(1) Depth of overburden
(2) Width of pit
(3) Percent of finished grade
(4) Type of equipment used

Depth of Overburden

Valleys formed between the peaks of two adjacent overburden piles varies until the bases of the two overburden piles meet. After the two overburden piles have met, the valley between the peaks stay constant. To calculate at what depth overburden the bases of the two adjacent overburden piles meet for a certain pit width is as follows:

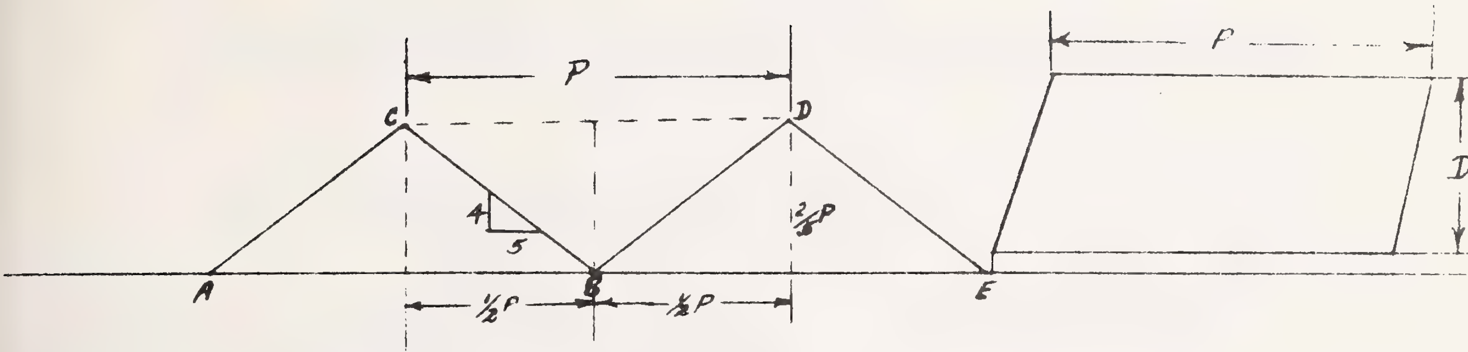

Figure #1

Slope of overburden piles is four on five. A cross section is taken of the pit area to be stripped, the overburden pile, and the valley that is formed between the overburden piles.

Area of the overburden piles = area of the valley that is formed between the peaks:

therefore,

triangle ABC = triangle BDC.

When stripping, overburden will swell 20%; therefore, area of overburden removed from cut plus 20% swell equals area of overburden piles.

P = width of pit
D = depth of overburden

Therefore,

area of the overburden removed from cut + 20% swell = P x D x 1.20.

To find the area of the overburden pile, the following statements are true.

Base of pile = P

1/2 of base of pile = 1/2P,

height of overburden pile = 1/2P x 4/5 = 2/5P;

therefore,

area of overburden pile = 1/2P x 2/5P = $\frac{P^2}{5}$

therefore,

$$P \times D \times 1.20 = \frac{P^2}{5}$$

$$1.20PD = \frac{P^2}{5}$$

$$D = \frac{P^2}{1.20P \times 5}$$

$$D = \frac{P}{6}$$

Using this formula, the following table was prepared:

Width Of Pit Stripped (in feet)	Depth Of Overburden That Can Be Stripped So The Bases Of The Two Adjacent Overburden Piles Meet. (in feet)
50'	8.33
60'	10.00
70'	11.76
80'	13.33
90'	15.00
100'	16.67
110'	18.33
120'	20.00
130'	21.67
140'	23.33
150'	25.00
160'	26.67
170'	28.33
180'	30.00
190'	31.67
200'	33.33

From the above table for a 200 foot pit, the bases of the adjoining overburden piles would meet at a depth of 33.33 feet. In most lignite mining, good commercial lignite has at least 35 to 40 feet of overburden; therefore, the above calculations are not used any further in this report.

Width of Pits

The distance between the peaks of two adjacent overburden piles is the same distance as the width of pit being stripped. Therefore, the size of the valley between two peaks is dirctly proportional to the width of pit stripped. This would indicate that narrow pits should be stripped. This would cause the valley between the peaks to be small and less material would be moved when leveling overburden areas. However, because of the large equipment which is necessary in the mining of lignite, it is necessary for the mining companies to strip as wide of pits as possible and this is usually dictated by the length of dragline boom and the overburden depth in their area.

To calculate the cubic yards of material that has to be moved to level an acre of spoil pile area, the following formula is used:

$$V = 80.76P$$

V is volume in cubic yards, P is the width of the pits or the distance between peaks. This formula is drived as follows:

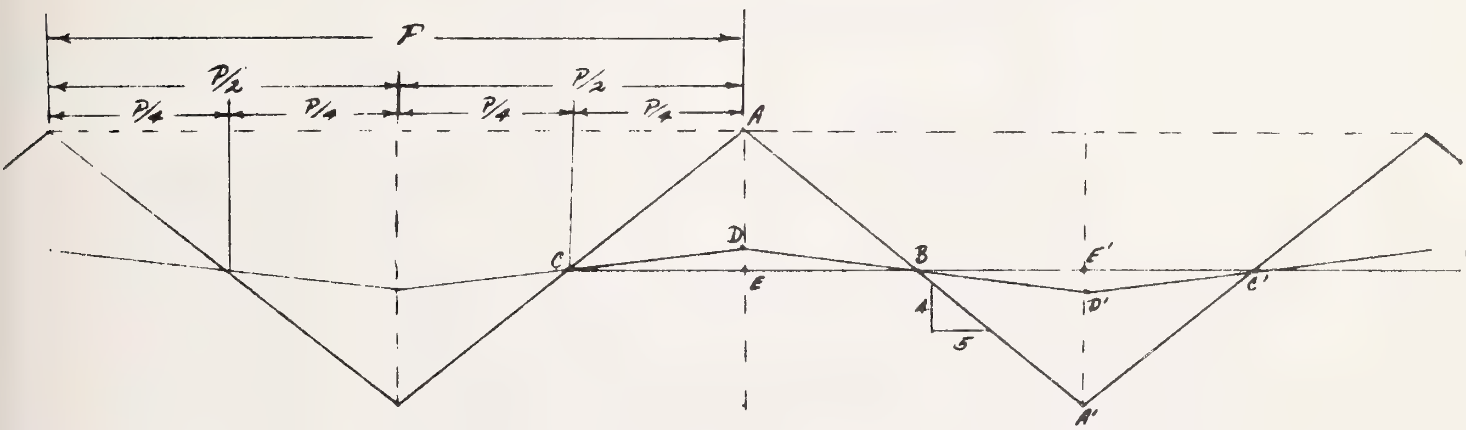

Figure #2

Slope of overburden piles 4 feet on 5 feet.

P = Distance between peaks = width of pit stripped.

$$CC' = P$$
$$CB = BC' = \frac{P}{2}$$
$$CE = EB = BE' = E'C' = \frac{P}{4}$$

43,560 sq. ft. per acre

Triangle ABC = A'BC'

Area of triangle = $\frac{\text{base x height}}{2}$

Also: BCD = BC'D'

therefore,

ABC - BCD = A'BC' - BC'D'

Area of triangle ABC

$$\text{Area} = \tfrac{1}{2}(CB \times AE) \qquad CB = \frac{P}{2}$$

$$= \tfrac{1}{2}\left(\frac{P}{2} \times \frac{P}{5}\right) \qquad AE = \frac{P}{4} \times \frac{4}{5}$$

$$= \tfrac{1}{2}\left(\frac{P^2}{10}\right) \qquad AE = \frac{P}{5}$$

$$= \frac{P^2}{20}$$

Cubic yards to move per acre

$$V.\ cu.\ yds = \frac{\text{area of triangle ABC} \times \frac{43{,}560}{P}}{27}$$

$$= \frac{\frac{P^2}{20} \times \frac{43{,}560}{P}}{27}$$

$$= \frac{2178P}{27}$$

(A) Vol. cu. yds. = 80.67P * overburden to move per acre to level overburden piles.

Per Cent of Predetermined Grade

In order to calculate the amount of overburden or the amount of material that has to be moved when leveling to a predetermined grade, refer to figure #2.

Line CDBD'C' = grade line.

Triangle CDB = triangle BC'D' = overburden not moved because of grade.

Triangle ABC - BCD = overburden to be moved.

G = predetermined grade.

* Use this formula except for the overburden piles from the first two cuts in any areas.

Cubic yards to be moved per acre.

$$V.\ cu.\ yds. = \frac{\text{area of triangle ABC - BCD} \times \frac{43,560}{P}}{27}$$

$$= \frac{\left(\frac{P^2}{20} \quad \frac{GP^2}{16}\right)\frac{43,560}{P}}{27}$$

$$= \frac{2178P - 2722.5GP}{27}$$

Area of triangle BCD

$$= \tfrac{1}{2}(CB \times DE)$$

$$= \tfrac{1}{2}\left(\frac{P}{2} \times \frac{GP}{4}\right)$$

$$= \tfrac{1}{2}\left(\frac{GP^2}{8}\right)$$

$$\text{Area} = \frac{GP^2}{16}$$

$$CB = \frac{P}{2}$$

$$DE = G \times \frac{P}{4}$$

(B) Vol. cu. yds. = 80.67P - 100.8GP*

(A) V = 80.67P
(B) V = 80.67P - 100.8 GP

V = Volume in cubic yards per acre
P = Pit width
G = Predetermined grade

Use "A" if overburden piles are to be leveled flat

Use "B" if overburden piles are to be leveled to a predetermined grade.

Using the formula, V = 80.76P - 100.8GP*, Table I has been calculated. This table gives the cubic yards of material to be moved per acre of overburden piles leveled for the various pit width and various percentages of grade. Slopes on the ditches in most areas on Interstate 94 are 25% grade. According to the State Highway Department they have no trouble pulling farm machinery on these grades. These areas are all seeded and the farmers cut hay on all these slopes. Therefore a minimum grade of not less than 25% seems reasonable.

Type of Equipment

Because of familiarity with dozer tractors, this piece of equipment has been used in calculating the cost per acre to level the overburden areas. For these calculations an International TD-25 tractor with a semi "U" blade has been used. This tractor is equivalent to Caterpillar's D-8 and Euclid's 82-40. Using the manufacturers graph on Estimated Production Capabilities of this tractor, the following production is estimated:

* Use this formula except for the overburden piles from the first two cuts in any areas.

TABLE I

CUBIC YARDS OVERBURDEN TO BE MOVED PER ACRE

Width of Pit	PER CENT GRADE 0	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30	32	34
50	4034	3933	3832	3732	3631	3530	3429	3328	3228	3127	3026	2925	2824	2724	2623	2522	2421	2320
60	4840	4719	4598	4477	4356	4235	4114	3993	3872	3751	3630	3509	3388	3267	3146	3025	2904	2783
70	5647	5506	5365	5224	5083	4942	4800	4659	4518	4377	4236	4095	3954	3813	3672	3530	3389	3248
80	6454	6293	6131	5970	5809	5648	5486	5325	5164	5002	4841	4680	4518	4357	4196	4035	3873	3712
90	7260	7079	6897	6716	6534	6353	6172	5990	5809	5627	5446	5265	5083	4902	4720	4539	4356	4176
100	8067	7865	7664	7462	7261	7059	6857	6656	6454	6253	6051	5849	5648	5446	5245	5043	4841	4640
110	8874	8652	8430	8209	7987	7765	7543	7321	7100	6878	6656	6434	6212	5991	5769	5547	5325	5103
120	9680	9438	9196	8954	8712	8471	8229	7987	7745	7503	7261	7019	6777	6535	6293	6052	5810	5568
130	10,487	10,225	9963	9701	9439	9177	8914	8652	8390	8128	7866	7604	7342	7080	6818	6556	6293	6031
140	11,294	11,012	10,730	10,447	10,165	9883	9600	9319	9036	8754	8472	8190	7908	7625	7343	7061	6779	6497
150	12,100	11,798	11,495	11,193	10,890	10,583	10,286	9983	9681	9378	9076	8774	8471	8169	7866	7564	7262	6959
160	12,907	12,584	12,262	11,939	11,617	11,294	10,971	10,649	10,326	10,004	9681	9358	9036	8713	8391	8068	7745	7423
170	13,714	13,371	13,029	12,686	12,343	12,000	11,658	11,315	10,972	10,629	10,287	9944	9602	9259	8916	8574	8231	7888
180	14,521	14,158	13,795	13,432	13,069	12,707	12,344	11,981	11,618	11,255	10,892	10,529	10,166	9803	9440	9077	8715	8352
190	15,327	14,944	14,561	14,178	13,795	13,412	13,029	12,646	12,263	11,880	11,497	11,114	10,731	10,348	9965	9582	9199	8816
200	16,134	15,730	15,328	14,924	14,521	14,118	13,715	13,312	12,908	12,505	12,102	11,699	11,296	10,892	10,489	10,086	9683	9280

TABLE II

Length of Push	60 Minute Hour - 80% Efficient Cubic Yards Material Moved	50 Minute Hour - 80% Efficient Cubic Yards Material Moved
50'	770	640
55'	720	600
60'	680	565
65'	650	540
70'	620	515
75'	600	500
80'	580	480
85'	560	465
90'	540	450
95'	520	430
100'	500	415

For estimating purposes a 50 minute hour - 80% efficiency is used.

TABLE III

OWNING & OPERATING COSTS

TD-25B - Code 200
Power Shift W/Hyd. Semi "U" Blade

LIST PRICE, F.O.B. FACTORY WITH STANDARD EQUIPMENT	$57,165.00
Replacement Tire Cost @ ---- Discount Off List Price	-----
Total List Price Less Tire Cost (Amount To Be Depreciated)	-----
HOURLY OWNERSHIP COSTS	
Depreciation: 10,000 Hours, 5 Years	$5.716
Interest, Insurance, Taxes: $0.03/1,000 x Price	1.715
TOTAL HOURLY OWNERSHIP COST	$7.431
HOURLY OPERATING COSTS	
Fuel: 8.5 gph @ $ .15 per gal.	$1.275
Engine Oil: .109 gph @ $ 1.00 per gal.	.109
Transmission Oil: .083 gph @ $ 1.00 per gal.	.083
Final Drive Lubricant: .012 gph @ $ 1.00 per gal.	.012
Steering and/or Hydraulic Oil: .037 gph @ $ .60 per gal.	.022
Chassis Lubricant: .08 lbs./hr. @ $ .18 per lb.	.014
Filter Costs for Average Conditions: (all filters)	.142
Tire Cost: Repl. Cost $ --- /Est. Life of --- Hours	----
Repairs and Labor: 90% of Depreciation Rate	4.433
Operator's Wage	3.713*
TOTAL HOURLY OPERATING COST	$9.803
TOTAL ESTIMATED HOURLY OWNERSHIP AND OPERATING COST	$17.234

*Labor includes 20% fringe benefits

Using Table III, Total Estimated Hourly Ownership and Operating Cost, and Table II, the following yardage costs are calculated:

TABLE IV

Length of Push	50 Minute Hour 80% Efficient Cubic Yards Moved Per Hour	Cost Per Cubic Yard of Material Moved
50'	640	0.027
55'	600	0.029
60'	565	0.031
65'	540	0.032
70'	515	0.033
75'	500	0.034
80'	480	0.036
85'	465	0.037
90'	450	0.038
95'	430	0.040
100'	415	0.042

Using the costs from Table IV and the yardage from Table I, the costs per acre are calculated for the various width of pits stripped and the percent of grade of the leveled overburden piles. This is found in Table V.

TABLE V

COST PER ACRE FOR LEVELING OVERBURDEN PILES

Width of Pit	PER CENT GRADE																	
	0	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30	32	34
50	$108.92	$106.19	$103.46	$100.76	$ 98.04	$ 95.31	$ 92.58	$ 89.86	$ 87.16	$ 84.43	$ 81.70	$ 78.97	$ 76.25	$ 73.55	$ 70.82	$ 68.09	$ 65.37	$ 62.64
60	130.68	127.41	124.15	120.88	117.61	114.35	111.08	107.81	104.54	101.28	98.01	94.74	91.48	88.21	84.94	81.68	78.40	75.14
70	152.47	148.66	144.86	141.05	137.24	133.43	129.60	125.79	121.99	118.18	114.37	110.57	106.76	102.95	99.14	95.31	91.50	87.70
80	174.26	169.91	165.54	161.19	156.84	152.50	148.12	143.77	139.43	135.05	130.71	126.36	121.99	117.64	113.29	108.95	104.57	100.22
90	196.02	191.13	186.22	181.33	176.42	171.53	166.64	161.73	156.84	151.93	147.04	142.16	137.24	132.35	127.44	122.55	117.61	112.75
100	217.81	212.35	206.93	201.47	196.65	190.59	185.14	179.71	174.26	168.83	163.37	157.92	152.50	147.04	141.62	136.16	130.71	125.28
110	257.35	250.91	244.47	238.06	231.62	225.19	218.75	212.31	205.90	199.46	193.02	186.59	180.15	173.74	167.30	160.86	154.43	147.99
120	300.08	292.58	285.08	277.57	270.07	262.60	255.10	247.60	240.10	232.59	225.09	217.59	210.09	202.59	195.08	187.61	180.11	172.61
130	335.58	327.20	318.82	310.43	302.05	293.66	285.25	276.86	268.48	260.10	251.71	243.33	234.94	226.56	218.18	209.79	201.38	192.99
140	372.70	363.40	354.09	344.75	335.45	326.14	316.80	307.53	298.19	288.88	279.58	270.27	260.96	251.63	242.32	233.01	223.71	214.46
150	411.40	401.13	390.83	380.56	370.26	359.99	349.72	339.42	329.15	318.85	308.58	298.32	288.01	277.75	267.44	257.18	246.91	236.61
160	464.65	453.02	441.43	429.80	418.21	406.58	394.96	383.36	371.74	360.14	348.52	336.89	325.30	313.67	302.08	290.45	278.72	267.23
170	507.42	494.73	482 07	469.38	456.69	444.00	431.35	418.66	405.96	393.27	380.62	367.93	355.27	342.58	329.89	317.24	304.55	291.86
180	551.80	538.00	524.21	510.42	496.62	482.87	469.07	455.28	441.48	427.69	413.90	400.10	386.31	372.51	358.72	344.93	331.17	317.38
190	613.08	597.76	582.44	567.12	551.80	536.48	521.16	505.84	490.52	475.20	459.88	444.56	429.24	413.92	398.60	383.28	367.96	352.64
200	677.63	660.66	643.78	626.81	609.88	592.96	576.03	559.10	542.14	525.21	508.28	491.36	474.43	457.46	440.54	423.61	406.69	389.76

EXHIBIT "B"

RECLAMATION COST PER ACRE IN RELATION TO COAL PRODUCED

TONS OF COAL PRODUCED PER ACRE

	10,000	15,000	20,000	25,000	30,000	35,000	40,000	45,000	50,000	55,000	60,000	65,000	70,000	75,000	80,000
$ 100.00	.010	.0067	.005	.004	.0033	.0029	.0025	.0022	.002	.0018	.0017	.0015	.0014	.0013	.0012
150.00	.015	.0100	.0075	.006	.0050	.0043	.0038	.0033	.003	.0027	.0025	.0023	.0021	.0020	.0019
200.00	.020	.0133	.0100	.008	.0066	.0057	.0050	.0044	.004	.0036	.0033	.0031	.0029	.0027	.0025
250.00	.025	.0166	.0125	.010	.0083	.0083	.0063	.0050	.005	.0045	.0042	.0038	.0036	.0033	.0031
300.00	.030	.0200	.0150	.012	.0100	.0086	.0075	.0067	.006	.0055	.0050	.0046	.0043	.0040	.0038
350.00	.035	.0233	.0175	.014	.0116	.0100	.0088	.0078	.007	.0064	.0058	.0054	.0050	[illegible]	.0044
400.00	.040	.0266	.0200	.016	.0133	.0114	.0100	.0089	.008	.0073	.0067	.0062	.0057	.0053	.0050
450.00	.045	.0300	.0225	.018	.0150	.0129	.0113	.0100	.009	.0082	.0075	.0069	.0064	.0060	.0056
500.00	.050	.0333	.0250	.020	.0166	.0143	.0125	.0111	.010	.0091	.0083	.0077	.0071	.0067	.0063
550.00	.055	.0366	.0275	.022	.0183	.0157	.0138	.0122	.011	.0100	.0092	.0085	.0079	.0073	.0069
600.00	.060	.0400	.0300	.024	.0200	.0171	.0150	.0133	.012	.0109	.0100	.0092	.0086	.0080	.0075
650.00	.065	.0433	.0325	.026	.0216	.0186	.0163	.0144	.013	.0118	.0108	.0100	[illegible]	.0087	.0081
700.00	.070	.0466	.0350	.028	.0233	.0200	.0175	.0156	.014	.0127	.0117	.0108	.0100	.0093	.0088
750.00	.075	.0500	.0375	.030	.0250	.0214	.0188	.0167	.015	.0136	.0125	.0115	.0107	.0100	.0094
800.00	.080	.0533	.0400	.032	.0266	.0229	.0200	.0178	.016	.0145	.0133	.0123	.0114	.0107	.0100
850.00	.085	.0566	.0425	.034	.0283	.0243	.0213	.0189	.017	.0155	.0142	.013	.0121	.0113	.0106
900.00	.090	.0600	.0450	.036	.0300	.0257	.0225	.0200	.018	.0164	.0150	.0138	.0129	.0120	.0113
950.00	.095	.0633	.0475	.038	.0316	.0271	.0238	.0211	.019	.0173	.0158	.0146	.0136	.0127	.0119
$1,000.00	.100	.0666	.0500	.040	.0333	.0286	.0250	.0222	.020	.0181	.0166	.0153	.0142	.0133	.0125

EXHIBIT "C"

SEED BED PREPARATION AND SEEDING COST TO ESTABLISH GRASS

First operation would be a chisel plow to be followed by a drag to smooth area. The second operation would be seeding and fertilizing. Dragging the area for seed coverage would be the last operation.

A Grass Seed Mixture @ 30# per acre	$ 9.00
Fertilizer @ 100# per acre	4.50
Chisel Plow*	1.50
Dragging*	1.40
Seeding*	1.60
	$18.00

*1969 Custom Rates for Western North Dakota

May increase seed and fertilizer by 100%.

Average cost per acre for seed and fertilizer and farming is $18 to $35.

XI. Pollution Control Task Force Technical Report

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NORTH CENTRAL POWER STUDY
POLLUTION CONTROL TASK FORCE
METHODS AND COSTS OF AIR POLLUTION CONTROL

I. General Assumptions

The general assumptions applicable to this section include:

1. The heat rate for a single 1000 Mw plant is 9400 Btu/kwh. This conforms to figures published in the third progress report.

2. The average heating value per pound of coal is 9500 Btu/lb, which was also used in the third progress report.

3. An "average" coal should be used for this section. There are substantial differences in the coals being studied, but these differences should not cause as much variation in the cost of air pollution control as differences in estimates of the sizes and costs of the equipment needed.

4. An average ash content of 9.0% was assumed.

5. An average sulfur content of 0.75% was assumed.

6. Allowable emissions as suggested in the Federal Register dated April 7, 1971 have been assumed.

7. The emission characteristics of pulverized coal dry bottom furnaces have been assumed.

8. Additional assumptions are detailed when made.

II. Fly Ash Collection

The technology of collecting dust from flue gas is relatively well developed with mechanical collections, scrubbers and electrostatic precipitators all offering certain advantages. When efficiencies over 95% are required and removal of dust is the only requirement placed on the equipment, electrostatic precipitators are generally specified by electric power plant builders because of their low operating cost and reliability.

In the case of low sulfur coal there has been difficulty experienced in achieving desired levels of collection efficiency with ordinary sizes of precipitators due to high resistivity of the collected dust. When this is a problem there are several alternatives:

1. Build the precipitator large enough to overcome any adverse operating condition.

2. Reduce the dust resistivity by operating at a temperature low enough to significantly increase the surface conduction of the particles.

3. Reduce the dust resistivity by operating at a temperature high enough to significantly increase the volume conduction of the particles.

4. Reduce the dust resistivity by injecting a suitable material into the gas stream.

A recent study performed by a utility company faced with choosing between these alternatives disclosed that the following conclusions could be drawn for a plant burning coal from the Colstrip area:

1. Avoiding the problem range of ash resistivity values above 10^{11} ohm-cm by operating at lower than conventional flue gas temperatures is the most economical choice.

2. Prices provided by each manufacturer were consistent in terms of dollars per square foot of collecting surface, regardless of gas volume or efficiency requirements, and therefore dollars per square foot of collecting electrode is a good basis for estimating precipitator costs.

It should be noted that conclusion one, above, may vary between alternates two, three and four depending on differences in fuel and details of plant configuration but the cost differences will not be large relative to the overall plant cost. Also there are no precipitators in operation anywhere with efficiencies over 99% on plants using coal from the area covered by this study so the cost estimates developed herein cannot be considered precise. The low gas temperature solution to handling high ash resistivity (conclusion one above) was therefore assumed for the following development.

The experience of the utility company referred to above indicates that a gas temperature of 260°F is low enough when using Colstrip area coal. The precipitator costs generated in the aforementioned study averaged $3.23 per square foot of collecting area required.

Assuming that a "clear" stack of about 0.015 grains per actual cubic foot is desirable the cost estimates are as developed on the following sheet. A rounded off figure of $3.75 per kw is suggested, which includes foundations, insulation, and lagging, but does not include cost of interconnecting ducting. This last item should be included in the base cost of the plant, as much of it is required whether or not there is a precipitator and it is not normally supplied by the precipitator vendor.

III. Sulfur Oxide Control

Neither the need for sulfur oxide scrubbing nor the technology by which it could be done can be clearly established for the plants covered by the study.

The allowable emissions proposed in the Federal Register of April 7, 1971, suggests that scrubbing is feasible and the 0.7% sulfur coal is an acceptable alternative. Since the average sulfur content of the coals being studied is around this figure, scrubbing may not be necessary.

The Clean Air Act Amendments of 1970 require the use of the best technology available. The Federal Power Commission paper transmitted to the Environmental Committee Chairman on April 8, 1971, states that over 40 different sulfur oxide processes have been suggested and tested but no acceptable technology exists. This statement seems to differ with the Federal Register article referred to before, but has been corroborated by statements from other groups. Therefore at this time it is not clear whether sulfur oxide scrubbing should be included in the study, and if so, what system should be selected as the basis of cost estimates.

For purposes of discussion, a cost has been estimated for one possible system as detailed on the two following sheets. The system considered is a wet limestone scrubbing process which removes fly ash as well as SO_2. The costs are based on a vendor's quotation to supply such a system to one utility company for a 350 Mw plant. Extrapolation of capital costs to other plant sizes was based on a conceptual study for the National Air Pollution Control Association by the TVA, as shown. Special operating costs were extrapolated by direct proportion to plant size. These operating costs include the cost of consumable chemical additive (limestone), the additional cost of fan pumping power, and the cost of reheating the moist plume from the scrubber. These have been converted to equivalent capital costs using the composite fixed charge rate of 10.57% shown in the fifth progress report. The total cost for a 1000 Mw plant then becomes $10.29/kw.

However, the system proposed was guaranteed to remove only 99% of the particulate matter while reducing the sulfur oxide content to the equivalent of 0.5% sulfur in the coal.

By comparison, costs of $5.00-$20.00/kw are in circulation in the industry for sulfur oxide removal, depending on the process considered, size of plant, sales assumed for any disposable by-product, whether or not special operating and maintenance costs are included, and whether or not the system requires separate particulate removal equipment.

In order to make the particulate removal function of the system considered here the equivalent of the precipitator discussed previously, a cost should be included for equipment to remove 1/2% of the total dust prior to the scrubbing system. However this would be a small refinement to a relatively inaccurate number and is therefore neglected.

Considering the foregoing, it appears two alternatives to consider are:

1. Assume sulfur oxide removal is not required and use the figure of $3.75/kw previously developed for precipitator.

2. If sulfur oxide removal is required substitute the figure $10.30/kw in lieu of the $3.75/kw, and recognize that the figure being used is subject to many uncertainties that cannot be better defined

until further technological development takes place.

IV. Nitrogen Oxide Control

The limit of about 500 ppm of nitrogen oxides proposed in the April 7, 1971 Federal Register is generally believed to be within the capability of the kind of boiler assumed here. Occasionally modified burner designs may have to be used, but the effect of these on the overall cost of the boiler should be negligable. Therefore, no additional costs are contemplated for control of this pollutant.

Should a boiler design be contemplated that cannot meet this limit it should be noted that no developmental work beyond the conceptual stage has been reported in the literature for nitrogen oxide removal systems.

V. Fugitive Dust

The nationally proposed limit of no visible fugitive dust escaping beyond property lines should be attainable with normal dust control practice. Therefore, no additional capital costs are contemplated.

VI. Ash Disposal

Special operating methods of covering ash disposal areas will probably have to be used. The method may vary depending on whether the ash is recovered wet or dry (that is, whether scrubbers or precipitators are used for ash collection). The costs should be in the same order of magnitude as the mined land (1-3 cents/ton). If a figure of 5 cents/ton is used to cover some of the unknowns, and an ash content of 9% is considered, adding 1/2 cent per ton to the cost of coal would cover this item.

All other costs associated with ash removal can be assumed to be included in normal operating cost estimates factored into the overall plant cost.

Ash handling systems adaptable for large power plants are either pneumatic or hydraulic. The pneumatic systems are either vacuum or pressure types. Type of system will depend to a great extent on the boiler selection and auxiliary equipment selection. The specific character and temperature of the ash to be handled and chemical characteristics of air and water conveying media will play an important part in the selection of ash handling equipment.

The trend for ash handling systems is toward fully automatic systems in the interest of economy of operation, however drastic variations in material characteristics will result in unsatisfactory and often failure of operation. Many stations have fully automatic flyash removal systems with semi-automatic or manual bottom ash removal systems.

Much has been done on the promotion and marketing of power plant ash. Contracts are successfully in operation for sale of slag and bottom ash to mix with asphalt for paving of highways. Flyash can be made into highgrade building brick and used as a light weight aggregate. Potential commercial uses of flyash are good but it is unlikely that any large volume consumption is readily available due to the remoteness of the area from existing factories. Provision should be made in the flyash conveying system for a possible future storage silo for offsite disposal. Provision should be made for bottom ash to be sluiced to a separate area for recovery as aggregate for road use.

Most of the ash must be conveyed to an on site storage area. Hydraulic conveyers with provisions for eliminating dust from the movement of flyash should be used. Sufficient land should be acquired with the site to provide 20 year's storage. Estimating coal with 9 per cent ash, the storage area would require 13.5 acres per year of use for each 1000 megawatts of capacity if the ash was deposited 20 feet thick. Federal and State specifications in strip mining operations require that the area be smoothed and covered with soil which is natural to the area and seeded to eliminate an environmental blight. Top soil should be stripped from the ash disposal area so that this provision can be met as the ash is deposited. Waste water from the various sluices should be discharged to a suitable clarifying basin to avoid stream pollution. Facilities should be installed to recirculate waste water in the conveying system.

Estimate of cost will vary with the site and proximity of the ash storage area to the boiler. Cost estimate is available at \$1.98 - \$2.05 per Kw in 1970 dollars exclusive of land costs and site storage preparation.

PRECIPITATOR COST ESTIMATES

Plant Size-Mw		350	500	750	1000
Heat Rate-Btu/kw hr. *		9660	9600	9500	9400
Heat Value-Btu/lb. *		9500	9500	9500	9500
Coal Consumption-tons/hr.		178	252	375	495
Ash Release @9.0%-lbs./hr.		32,000	45,400	67,600	89,100
Ash to Precip. @90% of Release-lbs./hr.		28,800	41,000	61,000	80,400
Gas Volume @ 260°F.-cfm		$1.2x10^6$	$1.75x10^6$	$2.6x10^6$	$3.5x10^6$
Inlet Grain Load-Gr/Acf		2.80	2.73	2.73	2.68
Outlet Grain Load Reqd.-Gr/Acf		0.015	0.015	0.015	0.015
Efficiency Reqd.-%		99.5	99.5	99.5	99.5
Sulfur Content of Coal-oven dried-%		0.6	0.6	0.6	0.6
Resistivity of Ash - ohm-cm		$6.5x10^{10}$	$6.5x10^{10}$	$6.5x10^{10}$	$6.5x10^{10}$
Precipitation Parameter-ft./sec.		0.30	0.30	0.30	0.30
Plate Area Reqd.-ft.^{2}		365,000	518,000	768,000	1,030,000
Cost @ \$323/ft.^{2} pl. area**	$	1,180,000	1,670,000	2,470,000	3,330,000
Cost (Bare Precipitator) \$/kw	$	3.38	3.34	3.31	3.33
Add for Fdns. & Siding @11.6%	$	.39	.39	.39	.39
Total Cost \$/kw (1971 Dollars)	$	3.77	3.73	3.70	3.72

* Third progress report
** Average of percent quotations

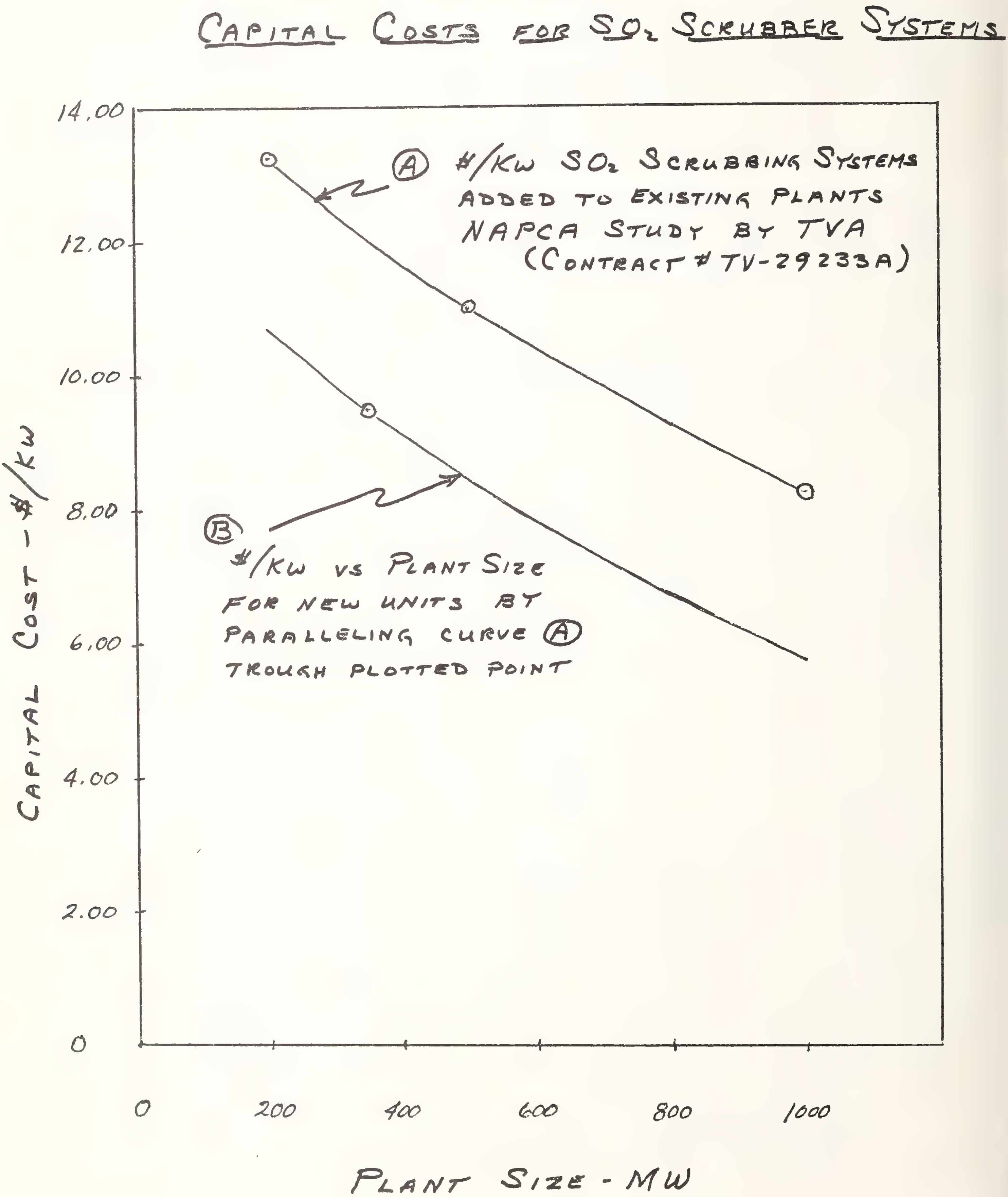
SULFUR DIOXIDE AND PARTICULATE SCRUBBER COSTS

Plant Size-Mw		350	500	750	1000
Scrubber System (quote for 350 Mw)	$	2,880,000*	---	---	---
Installed Cost	$	3,280,000	4,200,000	5,200,000	5,700,000
Cost $/kw**	$	9.38	8.40	6.95	5.70
+ Annual Limestone Costs $/yr.	$	90,000	129,000	193,000	256,000
+ Power & Stack Heating $/yr.	$	82,000	115,000	173,000	230,000
Total Special Operating Costs $/yr. (1972 Dollars)	$	172,000	244,000	366,000	486,000
Equivalent Capital Investment of Operating Costs @ 10.57% Fixed Charges	$	1,740,000	2,310,000	3,460,000	4,590,000
Equivalent $/kw	$	4.97	4.62	4.62	4.59
Total $/kw	$	14.35	13.02	10.57	10.29

NOTE: Scrubbers are not considered proven.

* Average of quotes

** Cost/kw for 350 Mw unit extrapolated to other sizes in same ratio as NAPCA conceptual study. See attached graph.



CAPITAL COSTS FOR SO2 SCRUBBER SYSTEMS
(A) $/KW SO2 SCRUBBING SYSTEMS
ADDED TO EXISTING PLANTS
NAPCA STUDY BY TVA
(CONTRACT # TV-29233A)
(B) $/KW VS PLANT SIZE
FOR NEW UNITS BY
PARALLELING CURVE (A)
TROUGH PLOTTED POINT
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0
CAPITAL COST - $/KW
0
200
400
600
800
1000
PLANT SIZE - MW

PLANT WATER QUALITY REQUIREMENTS

The quality of the water supply is not normally an important parameter in evaluation of plant location, but rather its quality is taken into consideration in plant design.

The requirement for water includes that needed for cooling, service water, potable water, and condensate make-up. The highest quality is that used for condensate make-up. The criteria is established by the boiler manufacture, with the limits being determined primarily by boiler operating pressure. The water plant is then designed to process the supply source of water to the required standards. The potable water can also be obtained from this water plant. No treatment other than chlorination is normally required for service and circulating water when using once through cooling. The water quality does influence the materials used in the heat transfer equipment however, such as condenser tubing.

Water treatment is an important consideration when employing cooling towers. To prevent excessive maintenance cost, water treatment is needed to prevent corrosion, deposition, biological growth, and for wood structures, chemical attack. The use of blowdown is used to prevent deposition. External treatment can be used to adjust analysis of the cooling water. They include (1) cold-process softening followed by acid feed to adjust PH and alkalinity, (2) ion-exchange softening followed by acid feed if needed and (3) sulfuric-acid feed for moderately hard waters with high alkalinity. Chemical inhibitors are used to check corrosion.

TYPE OF COOLING

Many methods and variations of these methods are available for heat rejection. These methods include once-through cooling, cooling ponds, spray ponds, mechanical and natural draft wet cooling towers, and mechanical and natural draft dry cooling towers. Selection of the type of cooling is based on many factors relating to the site and other economic considerations. For example, the cost of land, quality of source water, cost of source water, and the atmospheric conditions such as temperature and humidity.

The once-through cooling system is the lowest in capitol and operating cost, but present trends in regulations limit its use to relatively few locations. A major consideration in the selection of other types of cooling is that the cooling water temperature is generally higher than if natural bodies of water are used. This is important as the temperature of the water to the condenser has a strong effect on plant efficiency. The reason being that this results in a higher turbine back-pressure, thereby causing a loss in plant capacity. A second effect is an increased heat rate, which causes increased fuel cost. Dry cooling tower suffers severely in this aspect of evaluated cost, and wet cooling to a lesser degree.

For wet-cooling, the quantity of water required will depend primarily upon the need for blow-down, which is a function of the hardness of the source water. The total water demand can vary by a ratio of 2 to 1 because of this factor. Depending upon the availability and cost of water, it may be economical to minimize blow-down by water softening either the circulating water stream or the blow-down, and/or designing equipment to operate with highly concentrated water. A second consideration is drift, i.e., water lost as mist or fine droplets. If economically justifiable, it can be minimized by the type of cooling selected, such as natural draft cooling, and also by giving proper consideration to this aspect of water loss in the design of the tower.

If water is very scarce, consideration should be given to the dry-cooling tower as it requires only one percent of the water normal cooling towers use. Its disadvantage, however, in addition to the higher back-pressure, is initial cost. Current estimates of capital cost range from $22 to $40/KW versus $11/KW for wet cooling.

IMPACT

Water pollution presents no major obstacle which cannot be handled by careful design, but may involve some additional expenditures over those which have been experienced in the past.

The required treatment will depend upon State Regulations and more recently, Federal Regulation through enforcement of the Refuse Act of the Rivers and Harbors Act of 1899. Effective July 1, 1971, a permit for each discharge source into a navigable water is required from the Corp of Engineers who are working in conjunction with the Environmental Protection Agency. The purpose being to control waste discharges and thermal pollution. Furthermore, while the States are the primary enforcers of water quality standards, if they fail to act, the Secretary of the Interior may set the standards and enforce them. While standards of all States have now been approved, the Secretary excepted parts of them from initial approval and is negotiating with these States in an effort to bring their standards to an exceptable level.

As a result of these standards, the following items will have to be considered in the design of a power plant. (1) Some method of cooling the circulating water will probably be required to prevent thermal pollution. Should this result in cooling towers, careful consideration will have to be given to the method of handling the cooling tower blow-down. This may require evaporation ponds unless adequate chemical treatment can be provided to meet standards for water being returned to its source of supply. Cooling towers can also produce objectionable plumes, fog, and increase the duration of fog. The extent to which this will be a problem will depend upon meteorological condition, and the frequency and duration of undesirable atmospheric conditions. The extent to which this is a problem will determine the impact area for a given size plant. The basic meteorological data needed is wind, speed, wind direction, temperature and humidity. For natural draft towers, temperature and humidity data is needed over a vertical profile of 1200' for a single tower to 1700' for two towers. These measurements would be needed over a period of time to establish weather pattern histories. (2) Adequate sewage treatment facilities will be needed. (3) Consideration will have to be given to the handling of runoff from ash storage basins, such as an evaporation basin or a holding pond for settling and perhaps chemical treatment. (4) Plant acid-cleaning discharges will have to be carefully controlled. (5) Consideration given to the coal pile drainage to provide means of trapping dust and prevent accumulation of water having high or low PH, depending upon the coal characteristics.

While thermal pollution is a very serious problem, the heating of waters may have a beneficial effect in some areas, such as on large lakes having cold waters. Another beneficial effect might be the use of these warm waters for agriculture purposes.

COOLING DEVICES & BRINE DISPOSAL FACILITIES

The purpose of this chapter is to discuss and evaluate the cooling devices and brine disposal facilities required at the proposed installations to assure that State-Federal water quality requirements will be met.

In the basic thermal-electric steamplant water is heated, converted to steam, and forced through turbines at high velocity. Steam may enter the turbines at temperatures of over $1,000^{\circ}$ F. and pressures in excess of 2,000 psi and may leave at temperatures less than 100° F. and pressures less than atmospheric. This low-pressure turbine exhaust steam must be returned to the boiler in a form that is easily handled. This is accomplished by cooling until it condenses back to water, thereby greatly reducing its volume.

This cooling process provides the source of a potential water pollution and environmental problem. If the cooling water is allowed to return to a river, lake, or reservoir, the heated discharge may significantly change the density, viscosity, vapor pressure and solubility of dissolved gasses. Biochemical changes brought about by heated discharges cause enzyme-produced catalytic action resulting in rapid chemical changes, taste and odor problems, and oxygen depletion. The biological effect of elevated temperature changes are increased metabolism, altered reproduction cycles, abnormal growth and development and changes in general distribution of species.

The Federal Water Pollution Control Act, as amended by the Water Quality Act of 1965, required the States and Federal Government to establish water quality standards for interstate waters. Each of the States in which plants have been located in this North Central Power Study have adopted State-Federal water quality standards. There are large variations in standards from area to area depending upon present quality of the water, adequacy and variability of the supply, and present and expected future uses of the water.

The more important criteria are summarized by State in the table on the following page.

As can be observed, most specific streams standards will permit increased salt concentrations and minor temperature changes. However, all States have a non-degradation clause which would make any substantial water quality deterioration due to salt concentrations or temperature changes doubtful.

Most States have adopted a temperature criteria which would permit a 4^{o} to 5^{o} F. rise in stream temperature. Since none of the plants in this study are located adjacent to a large stream which could assimilate quantities of heated discharge with minor increases in temperature all plants will have to use some form of cooling device.

Cooling Water Alternatives

There are three main coding device alternatives: cooling ponds, wet-cooling towers and dry-cooling towers. The facility used will depend primarily upon the economics of the development.

Cooling Ponds.--A cooling pond is the simplest method of cooling thermal discharges. In the North Central Power area the advantages of a cooling pond would be low cost because of low land value and good efficiency because of existing climatological factors. Assuming a pond area requirement of 1 acre per MW, ponds could vary from 1,000 to 10,000 acres for the 1,000 MW to 10,000 MW plants projected for construction in these studies. The makeup water is assumed to be 1.10 acre-feet per kwh x 10^{-6} or 9,350 acre-feet per year per 1,000 MW plant.

Summary Table of Water Quality Standards

	Classification	pH	DO	Temperature: Item	Temperature: Max.	Temperature: Max. Inc.	Ec	TDS
Montana								
Yellowstone R. below Laurel, Mont. Intake	BD_3	6.5–9.5	5 ppm	Temp. Range 32–85^oF		4^oF		
				Above 85^o		0.5^oF		
Tongue R. above Tongue R. Reservoir	BD_2	6.5–9.0	6 ppm	Temp. Range 32–67^oF		2^oF		
				Above 67^o		0.5^oF		
Tongue R. below Tongue R. Reservoir	BD_3	Same as Yellowstone						
Powder River	BD_3	Same as Yellowstone						
Wyoming								
Green River		6.5–8.5	6 ppm		78^oF	4^oF		
Powder, Tongue, E. Belle Fourche Rivers		6.5–8.5	6 ppm		78^oF	4^oF		
Colorado								
South Platte below Denver	Indus.	6.5–9.0 Change of 0.5	3 mg/l		93^oF		2,500	
North Dakota								
Little Missouri R.		7.0–9.0	5 mg/l		90^oF	5^oF		
Missouri		7.0–9.0	5 mg/l		85^oF	4^oF		
South Dakota								
Little Missouri	2c,3b,4	6.0–9.3	2 mg/l		93^oF		4,000	2,500

Cooling ponds offer an excellent potential for waterfowl development and a warm water fishery. If the average depth of the ponds was 5 feet or less, they should be attractive to waterfowl and deeper areas resulting from excavation for perimeter dikes would shelter fish. It is also possible that portions of the ponds could be used for such outdoor sports as swimming and water-skiing.

Wet-Cooling Towers.--The North Central Power Study has assumed water requirements and costs based upon wet-cooling towers.

There are three potentially adverse impacts from wet-cooling towers. Large amounts of water vapor are expelled from evaporative towers which can cause, under extreme climatological conditions, condensation resulting in ground level fog or drizzle. The North Central Power Study area, however, is relatively free of the type of climatological factors which could cause problems. Figure 1, however, does show an area of moderate hazard within the study area.

Water circulating through the tower system may require chemical treatment to prevent corrosion and inhibit biological growth and evaporative losses will concentrate the dissolved solids in the circulating supply. The blowdown could, therefore, have a detrimental effect on aquatic life.

Dry-Cooling Towers.--Dry-cooling towers appear to have the least damaging environmental effect of the three types of cooling devices available. Elevated air temperatures in the exit plume will be favorable

Figure 1

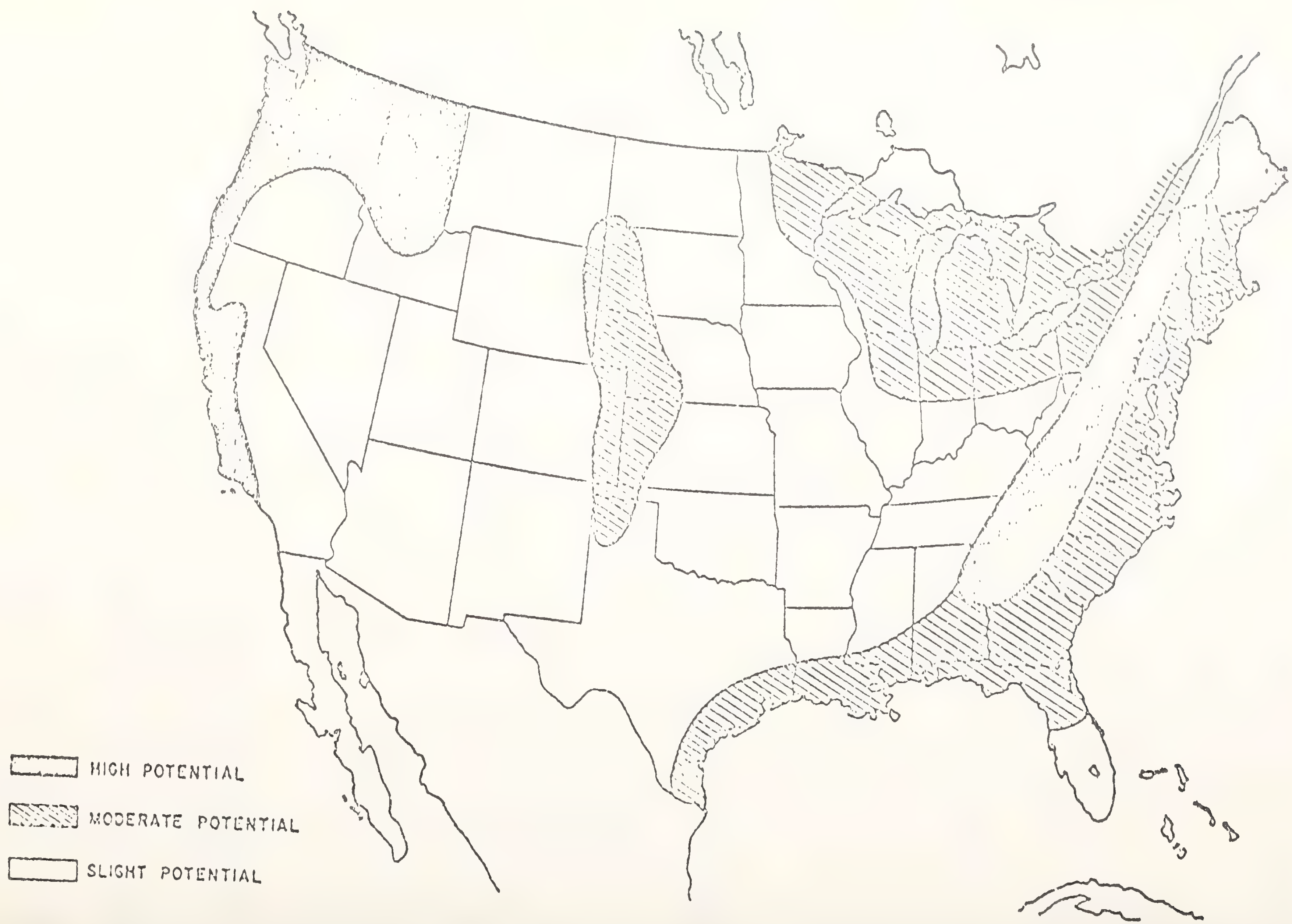


Figure 14. Geographical Distribution of Potential Adverse Effects from Cooling Towers, Based on Fog, Low-Level Inversion and Low Mixing Depth Frequency

to the dispersal of air pollutants, low stratus clouds, and local fog. Also, the large quantities of water required for the cooling pond and wet-cooling tower would be unnecessary for the dry-cooling tower alternative, thereby enhancing the conditions of the source stream if this alternative were used. The main disadvantage is economic; it is a great deal more expensive than the other alternatives.

Evaluation of Cooling Alternatives

The thermal generation task force has estimated costs for the 1,000 MW wet-cooling tower at $9.00 per net kw and an additional cost of $18.00 per net kw or a total of $27.00 per net kw for the 1,000 MW dry-type cooling tower. In addition, dry-type cooling towers have an incremental annual fuel cost of $804,000 and an additional O&M of $340,000. Because water demands were evaluated and pipelines sized on the wet-cooling tower alternative, this analysis will include a comparison of the cooling ponds and dry-type towers with the wet-cooling towers. At an overall plant efficiency of 37½ percent the energy required per kwh is 9,100 BTU. At a heat rate of 9,100 BTU/kwh (net at 85 percent plant factor) total inplant heat losses and output are estimated to be 4,200 BTU/kwh or a heat rejection potential of 4,900 BTU/kwh. It takes 1 BTU to reduce the temperature of 1 pound of water 1° F.; therefore, it would take .001803 acre-feet to remove the waste heat of 1 kwh - 1° F. If we assume a temperature rise of 25° F. in the cooling water, the total cooling water requirement would be:

$$\frac{.001803 \times 1{,}000{,}000 \times 85 \times 24 \times 365}{25^{\circ}\text{ F.}} \text{ or } 537{,}000 \text{ AF}$$

The makeup water required for the circulation of 537,000 acre-feet was estimated to be 17,440 AF/yr by the Thermal Generation Task Force.

Wet-Cooling Tower.—Assuming 1 percent evaporation loss per 10° F. of cooling and 0.2 percent drift loss, the blowdown per plant would be:

Total annual water delivery			17,440 AF
Evaporation	$537,000 \times \frac{25}{10} \times .01$	= 13,425	
Drift loss	$537,000 \times .002$	= 1,075	14,500
Blowdown			2,940 AF

Assuming an initial water quality of 650 ppm, blowdown from a 1,000 MW plant would be 3,855 ppm from the following computation:

$$650 \times 17,440 = CQ_2 \times 2,940$$

Wet-cooling tower effluent quality is predicted for each plant in Table 1.

The wet-tower effluent is too concentrated to be returned to a stream and therefore would need to be released to an evaporation pond for final disposal. The evaporation pond is estimated to cost about \$500,000 at \$250 per acre-foot of storage, a net evaporation rate of 3.0 acre-feet per acre and a 2-foot depth.

$$\frac{2,940}{3.0} \times 2.0 \times 250 = \$490,000$$

The alternative to this would be to design a system which would operate without blowdown. However, the quality of water available in the North Central power area does not lend itself to this application.

Dry-Tower Alternative

The difference in cost between a dry-type and wet-type cooling tower is \$18.00 per kw. Neglecting the minor water demands of a dry installation

Table 1

Water Quality Evaluation

North Central Power Study

Plant Location	Water Source	Receiving Stream	TDS Concentrate Water Supply	TDS Concentrate Wet Cooling Tower Effluent	TDS Concentrate Cooling Pond Total Supply 17,440
			- - - - - - - -	mg/l	- - - - - - - -
North Dakota					
Bowman #1	Little Missouri River	Little Missouri			
Bowman #2	Garrison Reservoir	" "	425	2520	915
N of Dickinson	Little Missouri River	" "			
Dickinson	Garrison Reservoir	" "	425	2520	915
Dickinson and Bowman	" "	" "	425	2520	915
Beulah	Missouri River	Knife River	425	2520	915
Center	" "		425	2520	915
South Dakota					
Ludlow	Little Missouri River	Little Missouri			
Colorado					
Watkins	South Platte River	South Platte	350	2075	755
Wyoming					
W of Kemmerer	Green River	Hams Fork	280	1660	605
NE of Rock Springs	" "	Muddy Creek	320	1900	690
N of Wamsutter	" "	Great Basin	320	1900	690
Gillette Vicinity, 10 plants	Bighorn River (Aqueduct)	Powder or Belle Fourche	650	3855	1400
Spotted Horse	" " "	Powder	650	3855	1400
Lake DeSmet	" " "	"	650	3855	1400

Table 1

Water Quality Evaluation

North Central Power Study
(continued)

Plant Location	Water Source	Receiving Stream	TDS Concentrate Water Supply	TDS Concentrate Wet Cooling Tower Effluent	TDS Concentrate Cooling Pond Total Supply 17,440
			- - - - - - - -	- mg/l -	- - - - - - - -
Montana					
NW of Brockway	Missouri River	Missouri	425	2520	915
Paxton	" "	"	425	2520	915
Richey	" "	"	425	2520	915
Fort Kipp	" "	"	425	2520	915
Reserve	" "	Muddy Creek	425	2520	915
Coal Ridge	" "	Missouri	425	2520	915
Wibaux	Yellowstone River	Little Missouri	425	2520	915
W of Savage	" "	Yellowstone	425	2520	915
Colstrip	" "	"	425	2520	915
NW of Brandenburg	" "	"	425	2520	915
SE of Ashland	Tongue River	Tongue River	430	2550	925
Birney	" "	" "	430	2550	925
Birney-PJ	" "	" "	430	2550	925
S of Birney	Tongue River Reservoir	" "	430	2550	925
	Bighorn River (Aqueduct)	" "	650	3855	1400
Kirby Alt. 1	Tongue River	" "	430	2550	925
Kirby Alt. 2	" "	" "	430	2550	925
Decker	" "	" "	430	2550	925
Volborg	Yellowstone River	Pumpkin Creek	425	2520	915
Camps Pass	" "	" "	425	2520	915
Sonnette	Powder River	Powder River	1100	6525	2370
Broadus	" "	" "	1100	6525	2370
Moorhead	" "	" "	1100	6525	2370

the break even point for a dry-type tower would be a water cost of \$154.00 acre-foot assuming a capitalization rate of 8 percent for 35 years.

$$\frac{(\$18.00 \times 1{,}000{,}000 \times .0858) + \$804{,}000 + \$340{,}000}{17{,}440} = \$154/AF$$

Since none of the plants were located where water would cost this much in the North Central Power Study area, it would appear that dry-type towers will not be economically feasible, although in some areas they may be necessary for public approval.

Cooling Ponds

Cooling ponds appear to be the most practical alternative to the wet-cooling tower. If the same quantity of makeup water was used for a flow-through cooling pond as was utilized for wet-cooling tower, makeup water effluent quality would vary from 605 to 2,370 ppm of TDS. This was based on an assumed evaporation rate of 1.1 acre-foot per net kwh x 10^{-6}.

$$\text{Evap. loss/1,000 MW} = 1.1 \times 1{,}000{,}000 \times .85 = 9{,}350 \text{ acre-feet}$$

Table 1 summarizes the effluent quality for each plant assuming a makeup water delivery of 17,440 acre-feet per 1,000 MW plant per year. As can be seen, effluent quality stays below 1,000 ppm except for Bighorn River and Powder River source water. The average water quality of the Powder River at the present time is about 1,100 ppm of TDS. Assuming this effluent would be satisfactory for a flow-through cooling pond, the quantity of makeup water for Bighorn River source water and Powder River return would be about 22,900 acre-feet per year per 1,000 MW plant.

$$650\ Q_1 = 1{,}100\ (Q_1 - 9{,}350)$$

$$Q_1 = 22{,}856$$

A flow-through cooling pond would not appear to be appropriate for Bighorn River source water returning to the Tongue River or Powder River water to any receiving stream.

Assuming a flow-through pond area requirement of 1 acre per MW of installed capability, a depth of 7 feet and a cost of $250/AF of storage, the pond would cost $1,750,000/1,000 MW plant.

$$1{,}000 \times 7 \times \$250 = \$1{,}750{,}000$$

XII. TRANSMISSION COMMITTEE

NORTH CENTRAL POWER STUDY
Report of the Transmission Committee

I. Conclusions

The principal objective of the Transmission Committee was to develop transmission plans adequate for delivery of power generated at the coal field sites to the selected delivery buses and to estimate costs of these plans. Conclusions are drawn as follows:

A. A technically feasible transmission system can be designed and built to deliver the magnitudes of power contemplated in the study. This can be done with presently available materials and devices.

B. The highest transmission voltages possible should be used for any project of this kind, where the impact upon the environment can be thereby minimized. It was therefore concluded that the highest commercially operable voltage available, 765 kv, should be used for the Eastern System. For the Western System, where lower levels of generation are contemplated and where the transmission distances assumed were much shorter, 500 kv would serve the purpose as well as the higher voltage and at a lower cost.

C. Multiple transmission lines should be routed through common corridors in such a manner as to strike a reasonable compromise between spatial diversification for reliability reasons on the one hand and minimization of environmental impact on the other.

D. For minimizing right-of-way requirements and for economic reasons, high levels of series reactive compensation are essential.

II. Summary

A. Task Force Functions

The Technical Studies Task Force developed a transmission system for the various stages of development and ran required load flow studies. The Design and Location Task Force developed detailed transmission facilities and unit costs for lines and substations.

B. Transmission Committee

Using information obtained from the task forces, the Transmission Committee developed estimated costs of constructing transmission for the various alternatives. These costs are shown in Tables T-1 through T-4. Basic transmission plans are described by Diagrams TSTF-1 through TSTF-8 in the Technical Studies Task Force Report.

III. Assumptions and Qualifications

A. Corridor Routing

The purpose served by routing transmission lines through a common corridor is to improve visual esthetics. Obviously, there must be a limit to the proportion of total transmission capacity located on any one right-of-way for reasons relating to reliability. Yet, if tests for reliability can reasonably accommodate some grouping of multiple lines, this should be done to reduce overall effects of the lines upon the landscape. It was therefore assumed that, for cost estimating purposes, a plan incorporating several corridors in the ultimate development would be most suitable.

B. Delivery points were established at: Des Moines, Gering, Kansas City, Oahe, Omaha, St. Louis, Twin Cities, and Utica Junction for the Eastern System and at Gillette and Medicine Bow for the Western System.

C. For Eastern and Western Systems 765-kv a-c and 500-kv a-c transmission voltages respectively were used.

D. Only presently available equipment was applied, although progress in technology may allow more advanced applications. High voltage d-c transmission was not included because there is no adequate d-c circuit breaker available at the present time.

IV. Results

Estimated costs of transmission alternatives described by Technical Studies Task Force Diagrams TSTF-1 through TSTF-8 are listed in Tables T-1 through T-4. These costs include allowances for contingencies, land and land rights, clearing, access roads, service facilities, investigations, construction engineering, preparation of designs and specifications, construction supervision, and other general expense but do not include interest charges during construction.

For purposes of estimating interest during construction, costs for all of the alternatives, for both Eastern and Western development, was spread as follows:

Year	Percent of total completion
1	5
2	20
3	40
4	30
5 (completion)	5
	100

This 5-year period was selected because of the unusually large size of the transmission construction.

Table T-5 shows costs of transmission for the various alternatives in dollars per kilowatt transmitted.

TABLE T-1

Eastern System
Estimated Transmission Costs
1970 Price Level

(In Millions of Dollars)

Facilities	Generation Level, MW					Annual O & M Cost * (%)
	3,000	10,000	20,000	40,000	43,000	
1. Transmission lines	456	807	1,273	2,288	2,568	0.4
2. Substations, switch yards, etc.	317	583	934	1,660	1,854	1.8
3. Control & Communi- cations equipment	15	28	44	79	88	5.0
4. Subtotal	788	1,418	2,251	4,027	4,510	
5. Allowance for im- proved appearance (3% of line 4)	24	43	67	121	135	
6. Total	812	1,461	2,319	4,148	4,645	

* % of total investment

TABLE T-2

Eastern System
Estimated Transmission Costs
1975 Price Level

(In Millions of Dollars)

Facilities	Generation Level, MW					Annual O & M Cost * (%)
	3,000	10,000	20,000	40,000	43,000	
1. Transmission lines	582	1,030	1,625	2,920	3,277	0.4
2. Substations, switch-yards, etc.	405	744	1,189	2,115	2,365	1.8
3. Control & Communication equipment	19	36	56	63	112	5.0
4. Subtotal	1,006	1,810	2,870	5,098	5,734	
5. Allowance for improved appearance (3% of line 4)	30	54	86	153	173	
6. Total	1,036	1,864	2,956	5,251	5,927	

* % of total investment

TABLE T-3

Western System
Estimated Transmission Costs
1970 Price Level

(In Millions of Dollars)

Facilities	Generation Level, MW			Annual O & M Cost (%)
	1,000	3,000	10,000	
1. Transmission lines	45.5	71.0	139.0	0.4
2. Substations, switch-yards, etc.	25.0	75.0	150.0	1.8
3. Control & communications equipment	1.5	3.0	6.0	5.0
4. Subtotal	72.0	149.0	295.0	
5. Allowance for improved appearance (3% of line 4)	2.0	4.5	9.0	
6. Total	74.0	153.5	304.0	

TABLE I-4

Western System
Estimated Transmission Costs
1975 Price Level

(In Millions of Dollars)

Facilities	Generation Level, MW			Annual O & M Cost (%)
	1,000	3,000	10,000	
1. Transmission lines	58.0	90.5	177.5	0.4
2. Substations, switch-yards, etc.	32.0	95.5	191.5	1.8
3. Control & communications equipment	2.0	4.0	7.5	5.0
4. Subtotal	92.0	190.0	376.5	
5. Allowance for improved appearance (3% of line 4)	3.0	5.5	11.5	
6. Total	95.0	195.5	388.0	

TABLE T-5

Transmission Unit Costs

Eastern System

Generation level (mw)	Estimated costs (millions of $) 1970	Estimated costs (millions of $) 1975	Unit cost ($ per kw transmitted) 1970	Unit cost ($ per kw transmitted) 1975	Decrease in unit cost* (percent)
3,000	812	1,036	270.7	345.3	
10,000	1,461	1,864	146.1	186.4	46.0
20,000	2,319	2,959	116.0	148.0	20.6
40,000	4,148	5,294	103.7	132.4	10.6
43,000	4,645	5,928	108.0	137.9	-4.2

Western System

Generation level (mw)	Estimated costs (millions of $) 1970	Estimated costs (millions of $) 1975	Unit cost ($ per kw transmitted) 1970	Unit cost ($ per kw transmitted) 1975	Decrease in unit cost* (percent)
1,000	74	95	74.0	95.0	-
3,000	154	196	51.3	65.3	30.7
10,000	304	388	30.4	38.8	40.7

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* Relative to next lower generation level.

NORTH CENTRAL POWER STUDY

XIII. Transmission Design and Location Task Force Technical Report

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H. 10,000 mw Western System - 500 kv
I. 3,000 mw Eastern System - 500 kv - Beulah Plan
J. 3,000 mw Eastern System - 500 kv - Gillette Plan

V. Environmental Considerations

I. Summary

1. Cost estimating data (October 1970 prices)

The following costs were used in estimating the total cost of the transmission systems studied. The costs include allowances for contingencies, land and rights, clearing, access roads, service facilities, investigations, construction engineering, preparation of designs and specifications, construction supervision, and other general expenses, but do not include an allowance to minimize environmental impact:

a. Transmission lines (single circuit ac). -

(1)	765 kv (4-1,272 kcm/phase)	$230,000 per mile
(2)	500 kv (3-1,113 kcm/phase)	130,000 per mile
(3)	230 kv (1-954 kcm/phase)	44,000 per mile

b. Transformers. -

		1,800 mva (cost)	1,200 mva (cost)	900 mva (cost)	600 mva (cost)
(1)	765/500 kv	$2,800,000	$2,200,000	$1,950,000	$1,700,000
(2)	765/345 kv	3,500,000	2,700,000	2,300,000	1,900,000
(3)	500/345 kv				1,400,000

c. Power circuit breakers (design for three breakers per bay). -

		765 kv	500 kv
(1)	One breaker initially	$2,200,000	$1,200,000
(2)	Two breakers initially	2,750,000	1,500,000
(3)	Adding one breaker to (1) or (2)	650,000	360,000
(4)	Three breakers initially	3,300,000	1,800,000

d. Reactors with switch. -

(1)	765 kv, 600 MVAR	$1,800,000
(2)	500 kv, 200 MVAR	900,000

e. Series compensation. -

(1) 765 kv, 2,000-MVAR range - \$440,000 + \$8/KVAR
(2) 500 kv, 800-MVAR range - \$290,000 + \$7/KVAR

f. Step-up two-winding transformers. -

(1)	765 kv, 800- to 1,200-mva range	\$850,000 + \$1.30/kva
(2)	765 kv, 50-mva range	\$570,000 + \$2.30/kva
(3)	500 kv, 800-to 1,200-mva range	\$600,000 + \$1.25/kva

g. Communications and control. - Approximately 2 percent of total investment cost.

h. Annual operations and maintenance costs in percent of total investment. -

(1) Transmission lines - 0.4 percent
(2) Substations, switchyards, etc. - 1.8 percent
(3) Control and communications - 5.0 percent

. Design assumptions

he following design assumptions were used:

a. Transmission lines. -

(1) Towers to be galvanized steel lattice type. Painted or steel pole towers not considered justified as periodic repainting would greatly increase maintenance costs and steel pole towers require more steel and other materials which are nonreplenishable natural resources.

(2) Self-supporting towers were selected for costing purposes; however, guyed towers could be considered for final designs.

(3) Some effort would be made to slenderize tower outline and minimize use of secondary members to improve appearance.

(4) Rights-of-way for transmission lines would not require fencing.

(5) Conductor sizes were selected on the basis of audible noise considerations and are larger than usually required on an economic basis. It may be possible to develop an economical expanded self-damping conductor for final designs.

(6) Not more than four corridors would be used for the lines to the east.

(7) The number of separate rights-of-way per corridor would not exceed two.

(8) The minimum distance between rights-of-way would be 0.75 mile.

(9) The number of circuits per right-of-way would not exceed two.

(10) Joint utilization of rights-of-way considered desirable, but decision in this regard should be made at national level. One concept would be to have major corridors one mile wide, spaced 100 miles or more apart, and used for highways, railroads, overhead transmission lines, underground transmission lines, gas lines, oil lines, communications lines, water lines, parks, etc. Minor corridors at shorter intervals could be added as needed.

(11) Additional transmission line data for systems studied are included in Transmission, Design, and Location Appendix.

b. Substations, switchyards, etc. -

(1) Uncluttered low-profile type.

(2) No guyed structures adjacent to substations.

(3) No latticed structures in substation.

(4) Equipment and structures to be painted except that galvanized steel would be used for structures which, if painted, would require bus outages for periodic repainting.

(5) Ring bus arrangement, convertible to breaker-and-one-half scheme, would be used for up to six circuits.

(6) Breaker-and-one-half scheme used for more than six circuits.

(7) Bus sectionalizing breakers included to increase reliability when more than twelve circuits installed.

(8) Switching stations or substations were included whenever 765-kv line lengths exceed 300 miles. All reactors and line compensation would be located in these stations.

(9) Switching arrangements used for cost estimates for the systems.

(10) For lack of more definite information on site locations, four plant sites covering a distance of approximately 30 miles were assumed at the Gillette-Colstrip complex area.

c. Transmission System Location. -

(1) Most direct routes that would miss Black Hills National Forest were used in establishing line mileages.

(2) It was assumed that substations would be located 20 to 30 miles outside city limits.

(3) Additional costs to conform to reasonable environmental criteria would not exceed 3 percent of total investment costs.

II. Transmission line data

Nominal voltage (kv)	765	500
Maximum voltage (kv)	800	550
Conductor		
Number per phase	4	3
Size (kcm)	1,272	1,113
Outside diameter (inches)	1.382	1.259
Continuous capacity for 70° C conductor temperature		
*Per conductor (amperes)	940	900
Per phase (amperes)	3,760	2,700
Per circuit at nominal voltage (mw)	5,000	2,340
Recommended 1 hour capacity, conductor temperature 93° C		
*Per conductor (amperes)	1,200	1,150
Per phase (amperes)	4,800	3,450
Per circuit at nominal voltage (mw)	6,400	3,000
**Approximate voltage gradient		
Center phase (kv peak/cm)	20.5	20.3

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*The 70° C conductor temperature used for continuous capacity is the maximum temperature recommended by NEMA Publication SG 1, Paragraph SG1-3.04. Data in Section 6 of Alcoa Conductor Engineering Handbook was used to determine current ratings and are based on 2 fps wind, 40° C ambient, and 0.5 emissivity effect with sun. The formulas for determining current ratings can be found in AIEE Transaction Paper 58-41, February 1958, titled "Current-Carrying Capacity of ACSR." The recommended 1 hour capacity is based on not exceeding 93° C conductor temperature, the recommended temperature limit for ACSR conductor.

**Based on data in Chapter 2, Section 2.2 in EHV Transmission Line Reference Book published by EEI.

TABLE NO. 1E

NORTH CENTRAL POWER STUDY

Estimated Costs - 1970 Prices

	Estimated Costs (Millions of Dollars)				
	3,000 mw System	10,000 mw System	20,000 mw System	40,000 mw System	43,000 mw System
Transmission lines	456	807	1,273	2,288	2,568
Substations, switchyards, etc.	317	583	934	1,660	1,854
Control and communications	15	28	44	79	88
Subtotal	788	1,418	2,251	4,027	4,510
For improved appearance (3 percent of subtotal)	24	43	68	121	135
Total	812	1,461	2,319	4,148	4,645

TABLE NO. 2E

NORTH CENTRAL POWER STUDY

Estimated Costs - 1975 Prices

	Estimated Costs (Millions of Dollars)				
	3,000 mw System	10,000 mw System	20,000 mw System	40,000 mw System	43,000 mw System
Transmission lines	582	1,030	1,625	2,920	3,277
Substations, switchyards, etc.	405	744	1,192	2,119	2,366
Control and communications	19	36	56	63	112
Subtotal	1,006	1,810	2,873	5,102	5,755
For improved appearance (3 percent of subtotal)	30	54	86	153	173
Total	1,036	1,864	2,959	5,255	5,928

TABLE NO. 1W

NORTH CENTRAL POWER STUDY

Estimated Costs - 1970 Prices

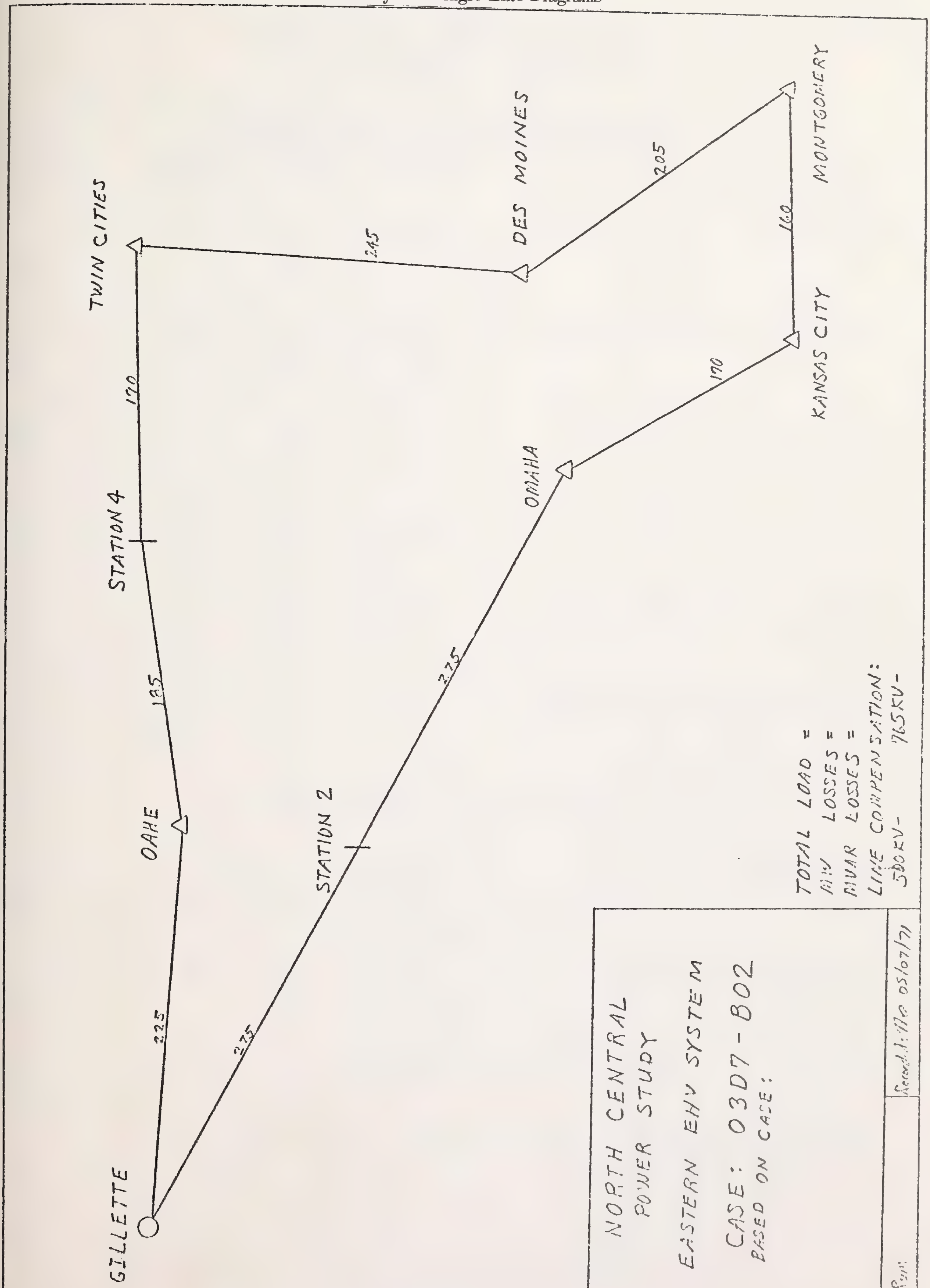
	Estimated Costs (Millions of Dollars)		
	1,000 mw System	3,000 mw System	10,000 mw System
Transmission lines	45.5	71.0	139.0
Substations, switchyards, etc.	25.0	75.0	150.0
Control and communications	1.5	3.0	6.0
Subtotal	72.0	149.0	295.0
For improved appearance (3 percent of subtotal)	2.0	4.5	9.0
Total	74.0	153.5	304.0

TABLE NO. 2W

NORTH CENTRAL POWER STUDY

Estimated Costs - 1975 Prices

	Estimated Costs (Millions of Dollars)		
	1,000 mw System	3,000 mw System	10,000 mw System
Transmission lines	58.0	90.5	177.5
Substations, switchyards, etc.	32.0	95.5	191.5
Control and communications	2.0	4.0	7.5
Subtotal	92.0	190.0	376.5
For improved appearance (3 percent of subtotal)	3.0	5.5	11.5
Total	95.0	195.5	388.0


TWIN CITIES
DES MOINES
MONTGOMERY
KANSAS CITY
OMAHA
STATION 4
STATION 2
OAHE
GILLETTE
170
245
205
160
190
135
225
275
275
TOTAL LOAD =
MW LOSSES =
MVAR LOSSES =
LINE COMPENSATION:
500KV- 765KV-
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 03D7-B02
BASED ON CASE:
Rev:

770

NCPS
EASTERN EHV SYSTEM
CASE 03D7-802

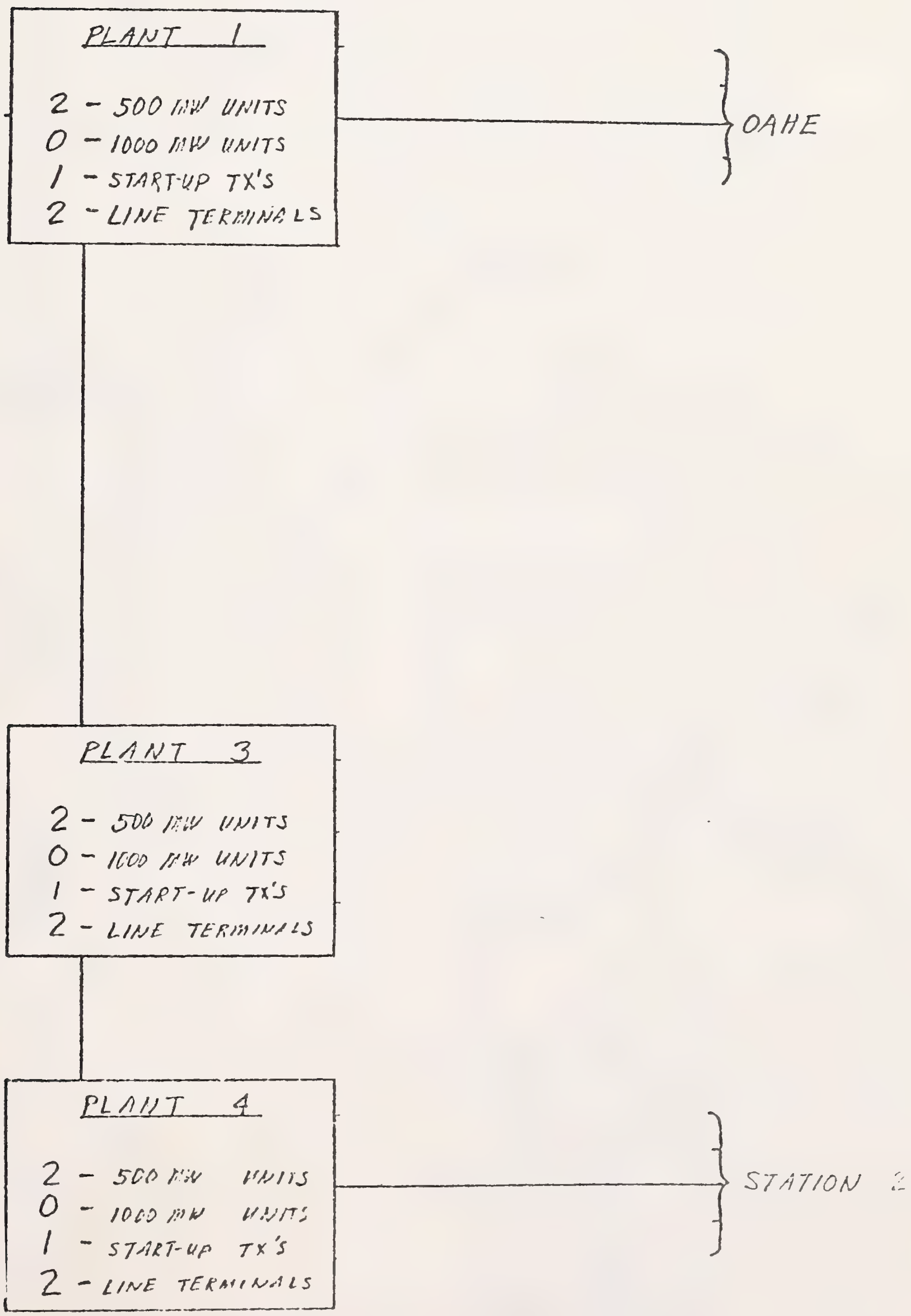
765 KV TRANSMISSION LINE DATA

TERMINAL 1 - TERMINAL 2	MILES	NUMBER OF LINES	TOTAL MILES	% SERIES COMP.
DES MOINES - MONTGOMERY	205.0	1	205.0	80
" " - OMAHA	130.0	0		80
" " - TWIN CITIES	245.0	1	245.0	80
" " - UTICA JCT.	220.0	0		80
GERING - GILLETTE	205.0	0		80
" - STATION 3	295.0	0		80
GILLETTE - OAHE	255.0	1	255.0	80
" - STATION 1	215.0	0		80
" - STATION 2	275.0	1	275.0	80
KANSAS CITY - MONTGOMERY	160.0	1	160.0	80
" " - OMAHA	170.0	1	170.0	80
" " - STATION 3	245.0	0		80
MONTGOMERY - OMAHA	280.0	0		80
OAHE - STATION 4	185.0	1	185.0	80
OMAHA - STATION 2	275.0	1	275.0	80
STATION 1 - UTICA JCT.	215.0	0		80
STATION 4 - TWIN CITIES	190.0	1	190.0	80
TWIN CITIES - UTICA JCT.	275.0	0		80
GILLETTE COMPLEX TIES	8.0	1	8.0	0
GILLETTE COMPLEX TIES	16.0	1	16.0	0
TOTAL MILEAGE (ALL 4-1272 MCM)			1984.0	

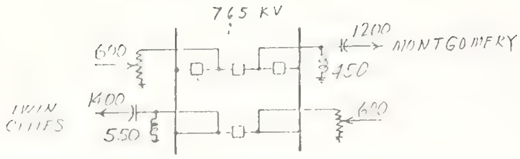
710 05/06/71

NCPS
EASTERN EHV SYSTEM
CASE 03D7-B02

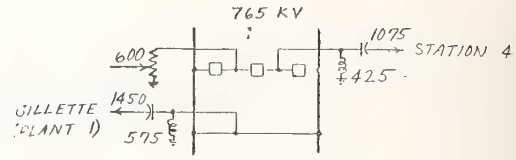
GILLETTE COMPLEX



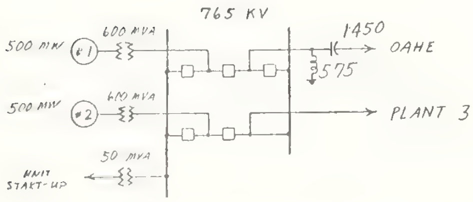
NCPS
EASTERN EHV SYSTEM
CASE 03D7-B02



DES MOINES SUBSTATION

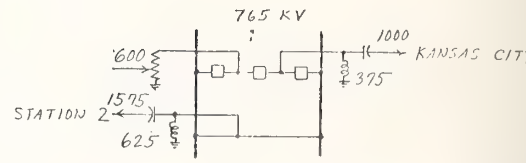


OAHE SUBSTATION

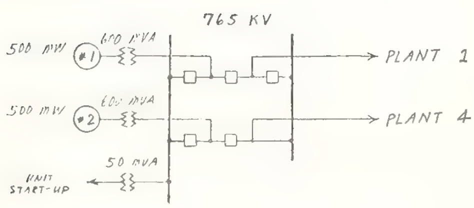


GILLETTE COMPLEX

PLANT 1

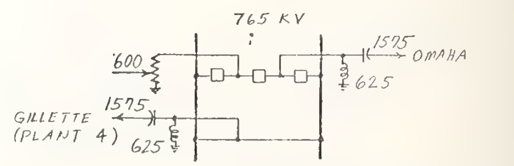


OMAHA SUBSTATION

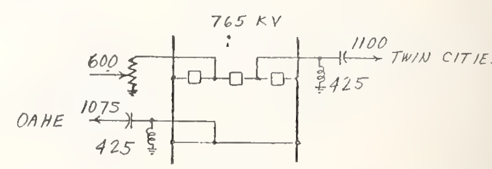


GILLETTE COMPLEX

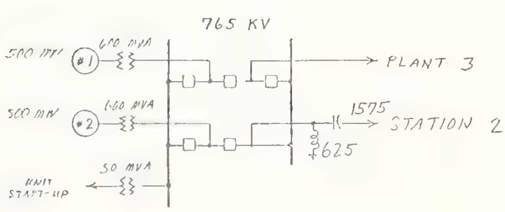
PLANT 3



SWITCHING STATION NO. 2

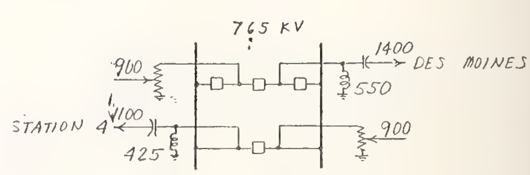


SWITCHING STATION NO. 4

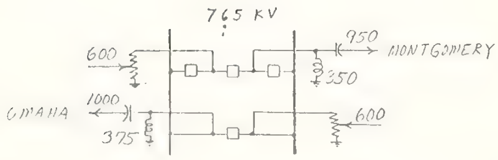


GILLETTE COMPLEX

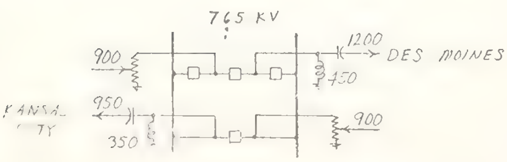
PLANT 4



TWIN CITIES SUBSTATION



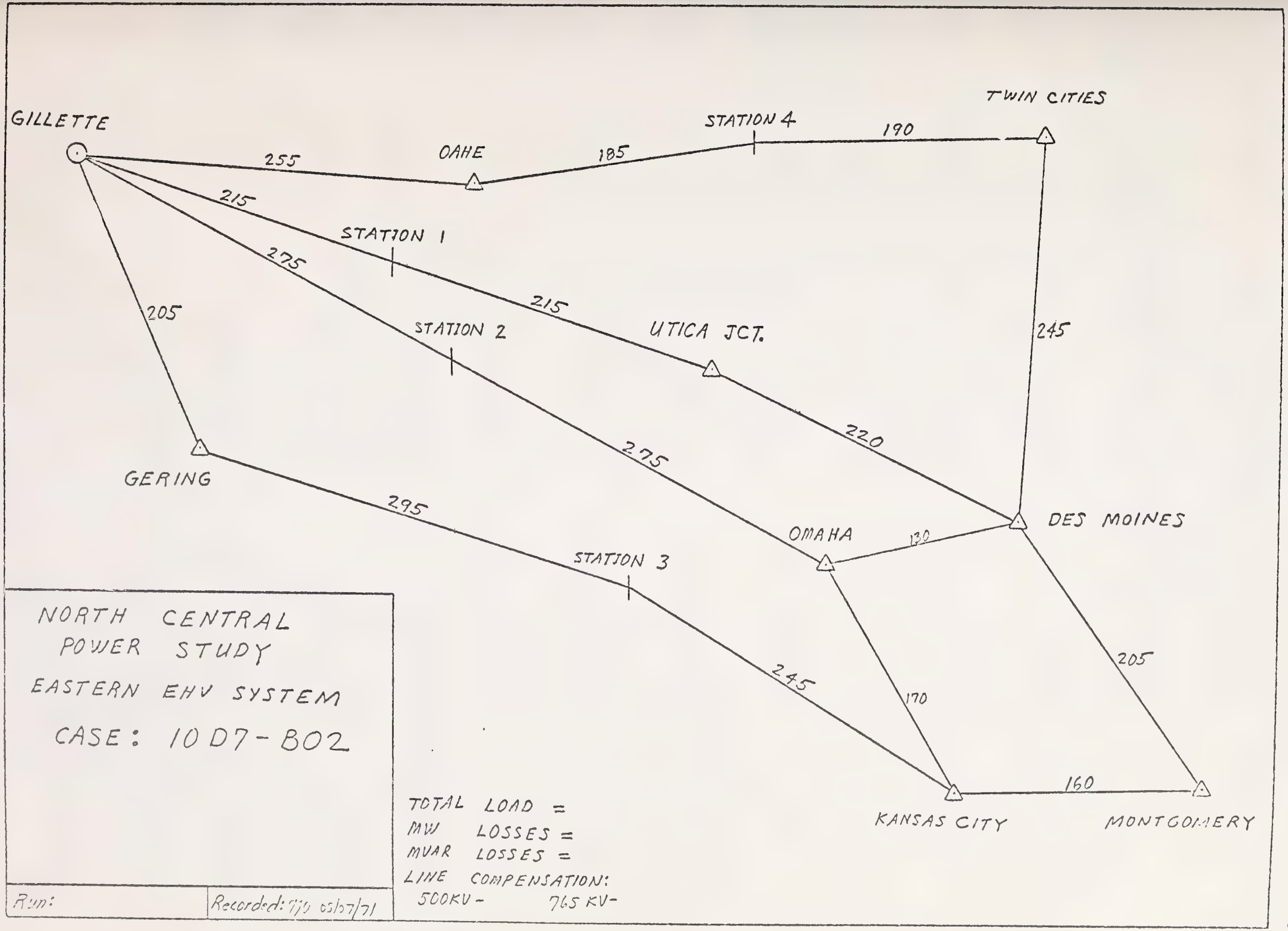
KANSAS CITY SUBSTATION



MONTGOMERY SUBSTATION

NOTES:

1. All reactor and capacitor values in mvar.
2. Generator unit transformers: 22/765 Kv, 1ϕ, total mva shown.
3. Start-up transformers: 22/765 Kv, 1ϕ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.


GILLETTE
OAHE
STATION 4
TWIN CITIES
STATION 1
UTICA JCT.
STATION 2
GERING
OMAHA
DES MOINES
STATION 3
KANSAS CITY
MONTGOMERY
255
185
190
215
215
220
275
275
205
295
245
245
130
170
205
160
NORTH CENTRAL POWER STUDY
EASTERN EHV SYSTEM
CASE: 10D7-B02
Run:
Recorded: 05/07/71
TOTAL LOAD =
MW LOSSES =
MVAR LOSSES =
LINE COMPENSATION:
500KV - 765 KV-

770 05/07/71

NCPS
EASTERN EHV SYSTEM
CASE 10D7-802

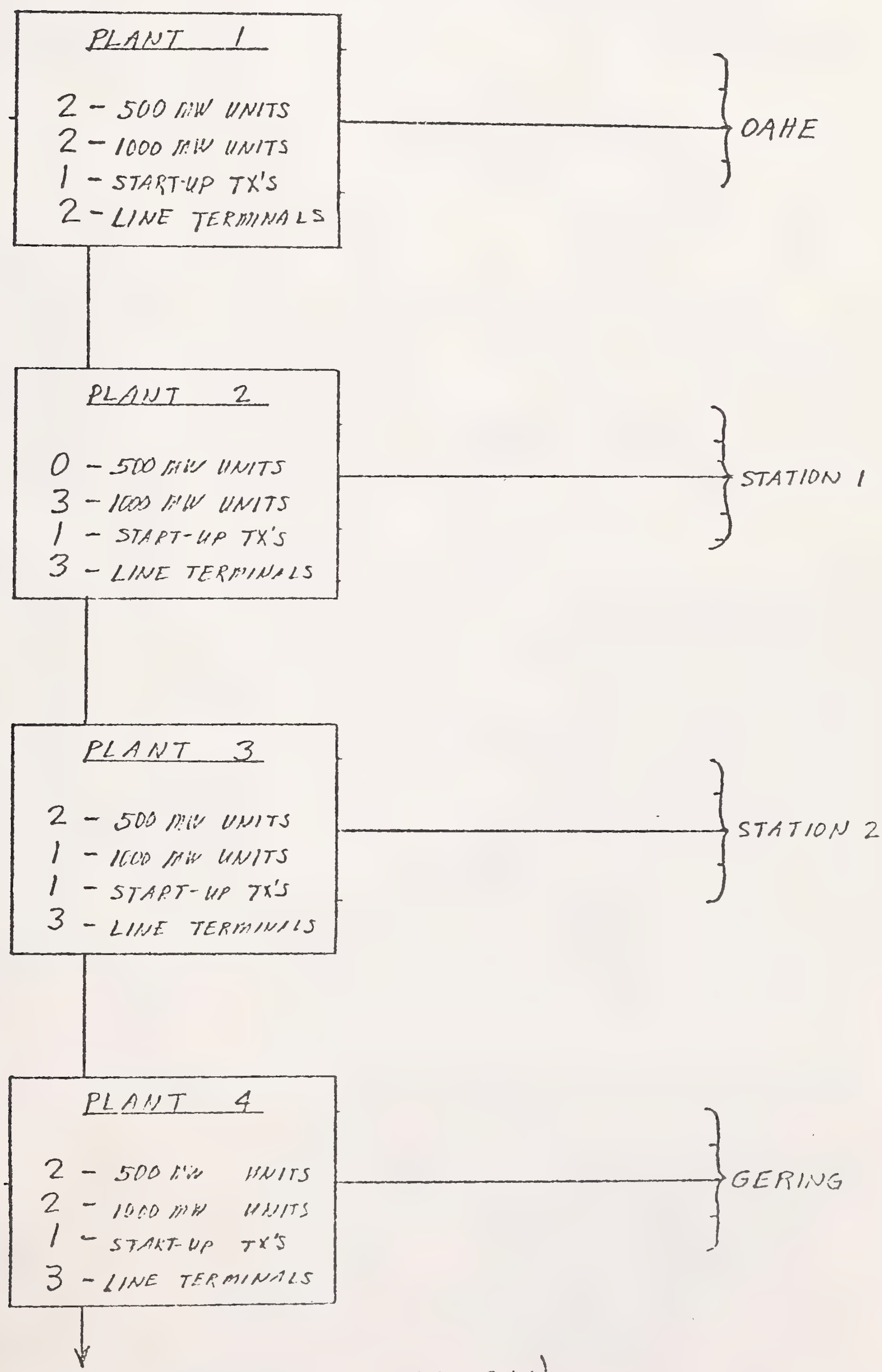
765 KV TRANSMISSION LINE DATA

TERMINAL 1 - TERMINAL 2	MILES	NUMBER OF LINES	TOTAL MILES	% SERIES COMP.
DES MOINES - MONTGOMERY	205.0	1	205.0	80
" " - OMAHA	130.0	1	130.0	80
" " - TWIN CITIES	245.0	1	245.0	80
" " - UTICA JCT.	220.0	1	220.0	80
GERING - GILLETTE	205.0	1	205.0	80
" - STATION 3	295.0	1	295.0	80
GILLETTE - OAHE	255.0	1	255.0	80
" - STATION 1	215.0	1	215.0	80
" - STATION 2	275.0	1	275.0	80
KANSAS CITY - MONTGOMERY	160.0	1	160.0	80
" " - OMAHA	170.0	1	170.0	80
" " - STATION 3	245.0	1	245.0	80
MONTGOMERY - OMAHA	280.0	0		80
OAHE - STATION 4	185.0	1	185.0	80
OMAHA - STATION 2	275.0	1	275.0	80
STATION 1 - UTICA JCT.	215.0	1	215.0	80
STATION 4 - TWIN CITIES	190.0	1	190.0	80
TWIN CITIES - UTICA JCT.	275.0	0		80
GILLETTE COMPLEX TIES	8.0	3	24.0	0
GILLETTE COMPLEX TIES		0		0
TOTAL MILEAGE (ALL 4-1272 MCM)			3509.0	

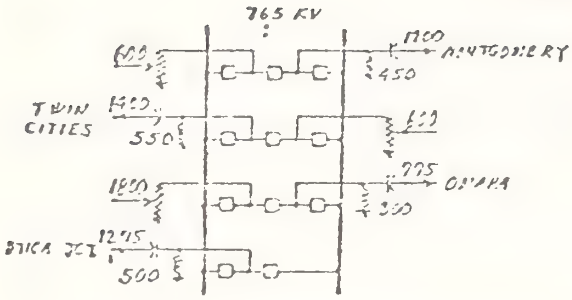
710 05/06/71
REV. 06/25/71 770

NCPS
EASTERN EHV SYSTEM
CASE 10D7-B02

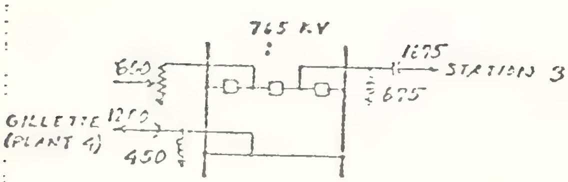
GILLETTE COMPLEX



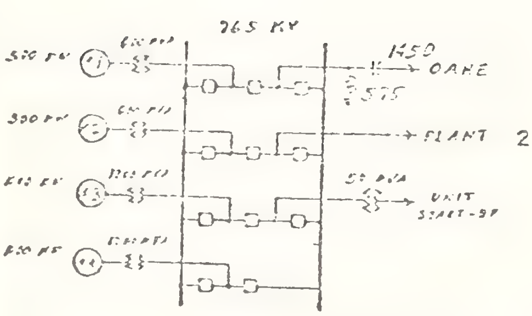
NCPS
EASTERN EHV SYSTEM
CASE 1007-802



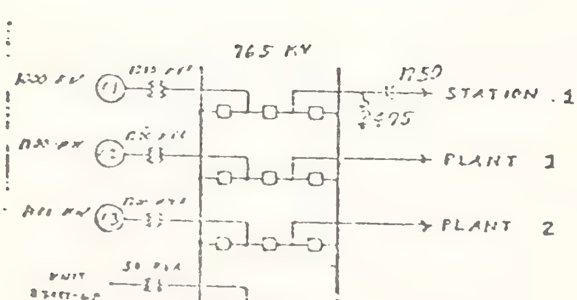
DES MOINES SUBSTATION



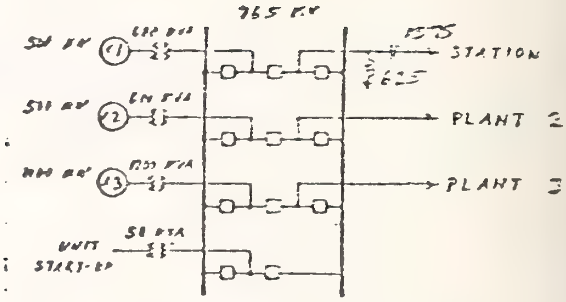
GERING SUBSTATION



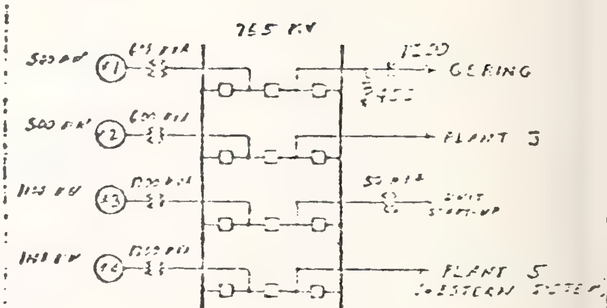
GILLETTE COMPLEX
PLANT 1



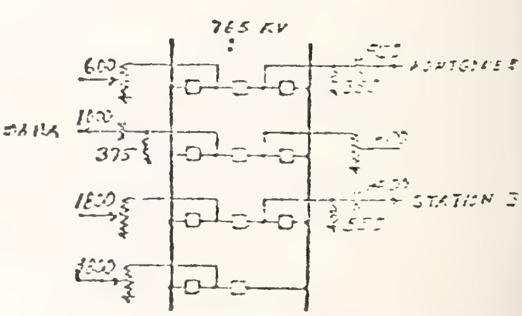
GILLETTE COMPLEX
PLANT ?



GILLETTE COMPLEX
PLANT 3



GILLETTE COMPLEX
PLANT 4

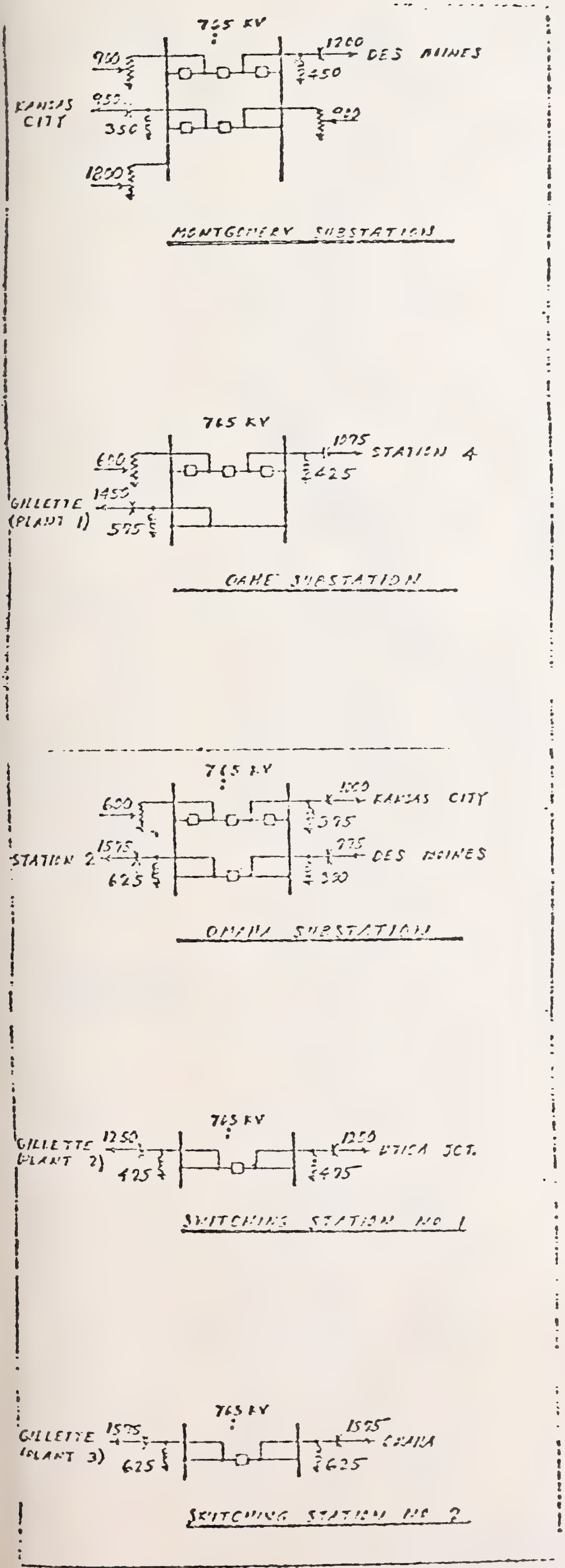


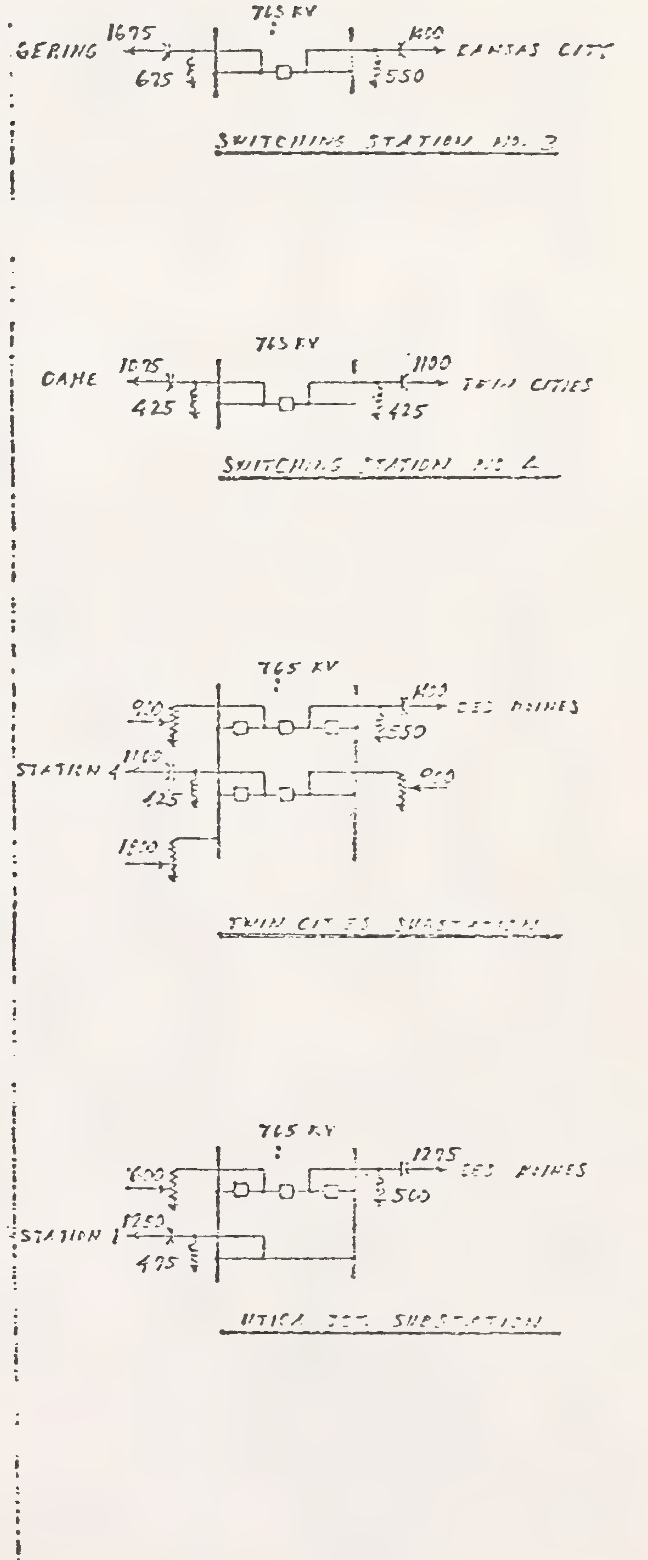
KANSAS CITY SUBSTATION

NOTES:

1. All reactor and capacitor values in [illegible]
2. Generator unit transformers: 22/765 kv. [illegible] total [illegible] shown
3. Start-up transformers: 22/765 kv. [illegible] total [illegible] shown.
4. Substation step-down transformer rating are [illegible] and all are voltage rated 765/345 kv.

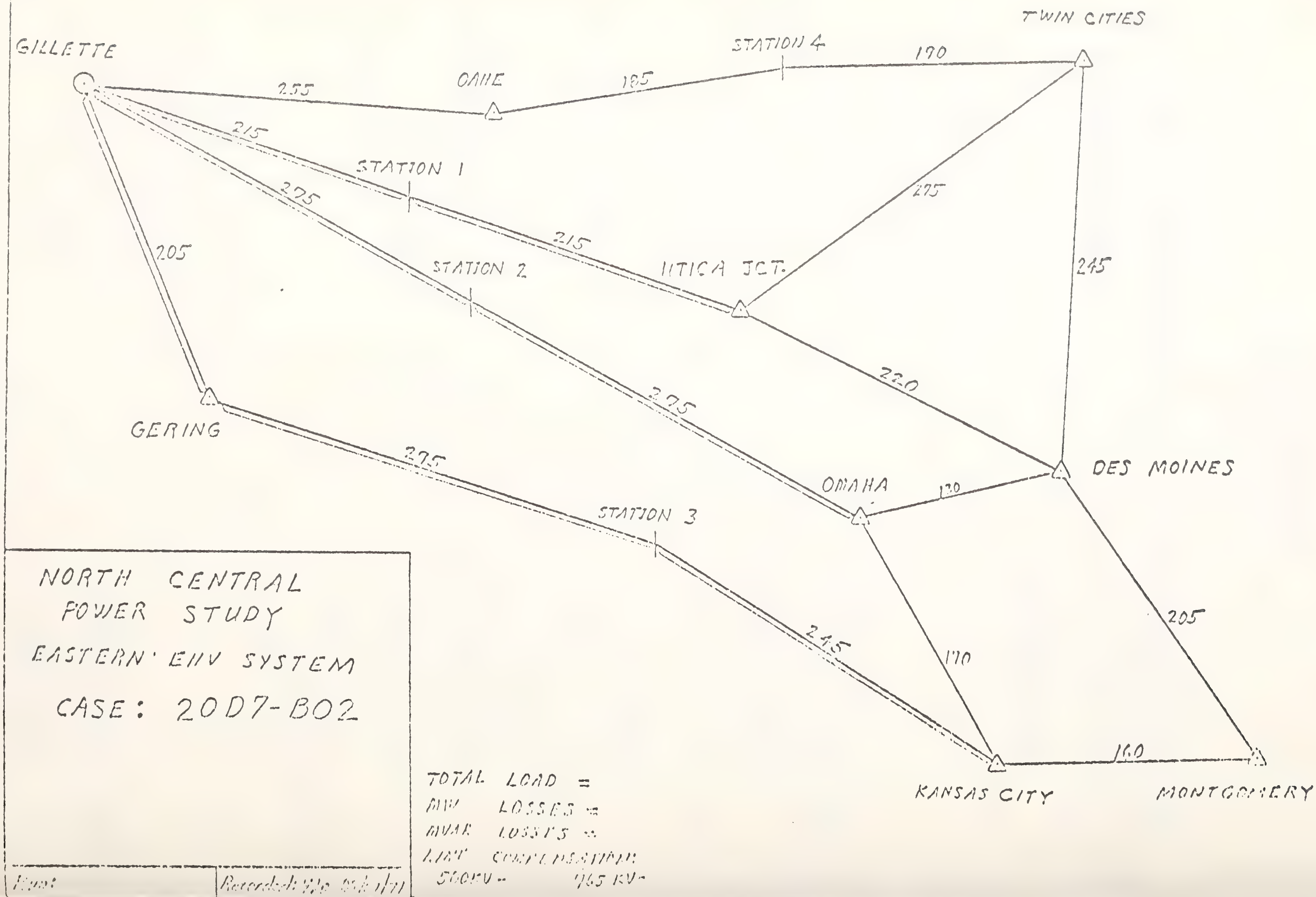
NCPS
EASTERN EHV SYSTEM
CASE 1007-802





NOTES:

1. All reactor and capacitor values in [illegible].
2. Generator unit transformers: 22/765 Kv. [illegible] total mva [illegible].
3. Start-up transformers: 22/765 Kv. [illegible] total mva [illegible].
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.


GILLETTE
OAHE
STATION 4
TWIN CITIES
255
185
190
215
STATION 1
275
275
205
215
STATION 2
UTICA JCT.
245
220
275
GERING
275
OMAHA
130
DES MOINES
STATION 3
245
170
205
160
KANSAS CITY
MONTGOMERY
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-B02
TOTAL LOAD =
MW LOSSES =
MVAR LOSSES =
500KV -
765 KV -

770 05/27/71

NCPS

EASTERN EHV SYSTEM

CASE 2007-802

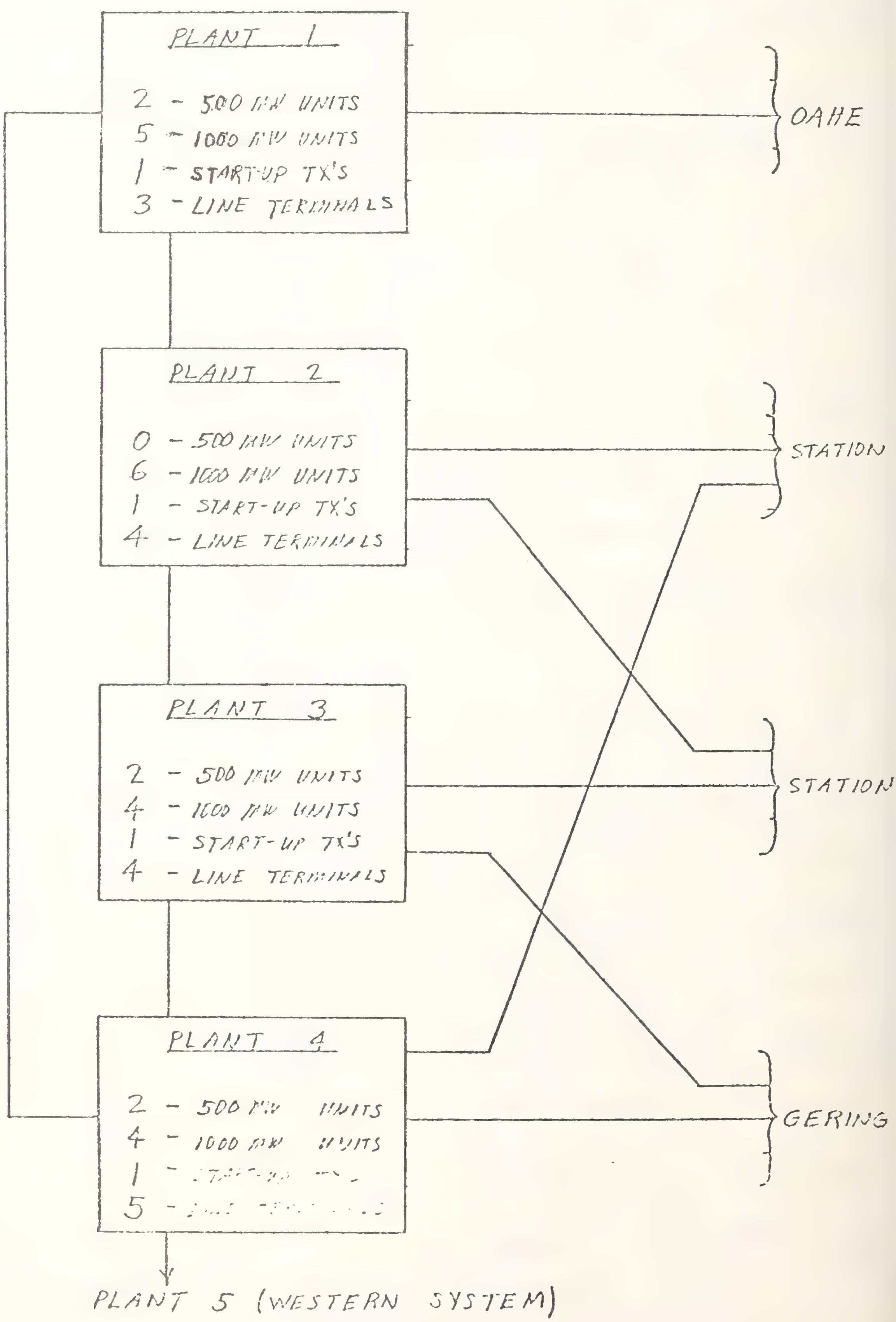
765 KV TRANSMISSION LINE DATA

TERMINAL 1 - TERMINAL 2	MILES	NUMBER OF LINES	TOTAL MILES	% SERIES COMP.
DES MOINES - MONTGOMERY	205.0	1	205.0	80
" " - OMAHA	130.0	1	130.0	80
" " - TWIN CITIES	245.0	1	245.0	80
" " - UTICA JCT.	220.0	1	220.0	80
GERING - GILLETTE	205.0	2	410.0	80
" - STATION 3	295.0	2	590.0	80
GILLETTE - OAHE	255.0	1	255.0	80
" - STATION 1	215.0	2	430.0	80
" - STATION 2	275.0	2	550.0	80
KANSAS CITY - MONTGOMERY	160.0	1	160.0	80
" " - OMAHA	170.0	1	170.0	80
" " - STATION 3	245.0	2	490.0	80
MONTGOMERY - OMAHA	280.0	0		80
OAHE - STATION 4	185.0	1	185.0	80
OMAHA - STATION 2	275.0	2	550.0	80
STATION 1 - UTICA JCT.	215.0	2	430.0	80
STATION 4 - TWIN CITIES	190.0	1	190.0	80
TWIN CITIES - UTICA JCT.	275.0	1	275.0	80
GILLETTE COMPLEX TIES	8.0	3	24.0	0
GILLETTE COMPLEX TIES	24.0	1	24.0	0
TOTAL MILEAGE (ALL 4-1272 MCM)			5533.0	

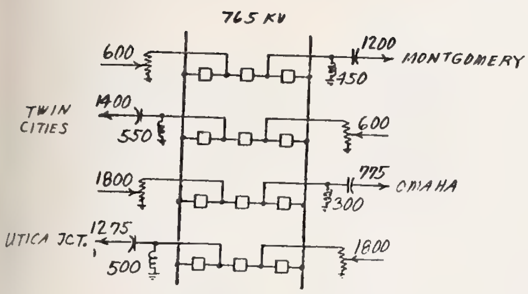
7/0 05/06/71
REV. 06/25/71 //O

NCPS
EASTERN EHV SYSTEM
CASE 20D7-B02

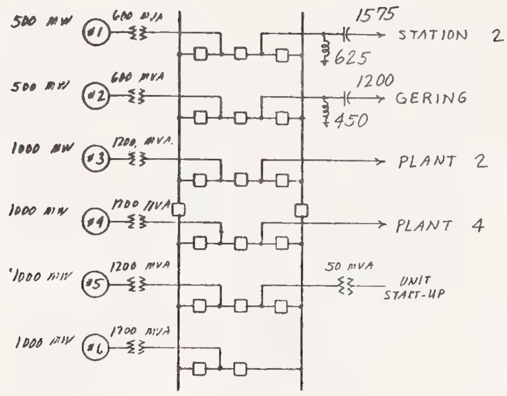
GILLETTE COMPLEX



NCPS
EASTERN EHV SYSTEM
CASE 20D7-802

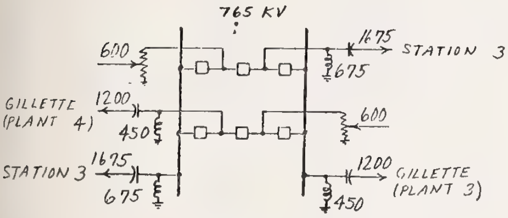


DES MOINES SUBSTATION

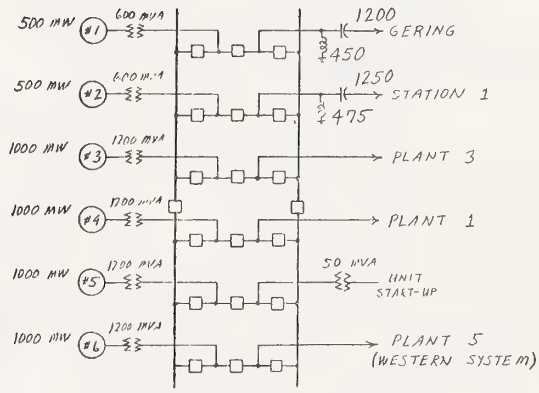


GILLETTE COMPLEX

PLANT 3

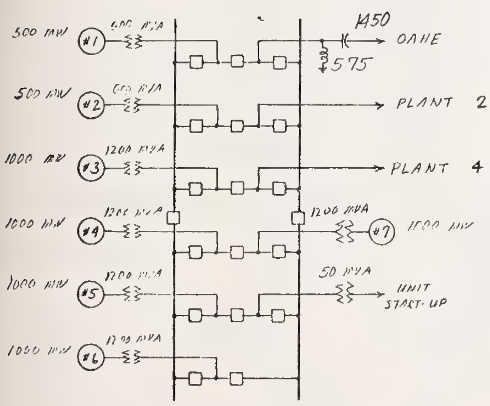


GERING SUBSTATION



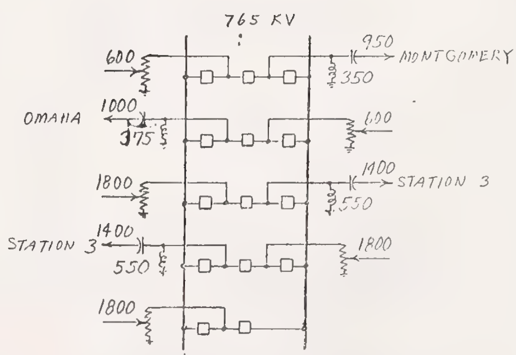
GILLETTE COMPLEX

PLANT 4

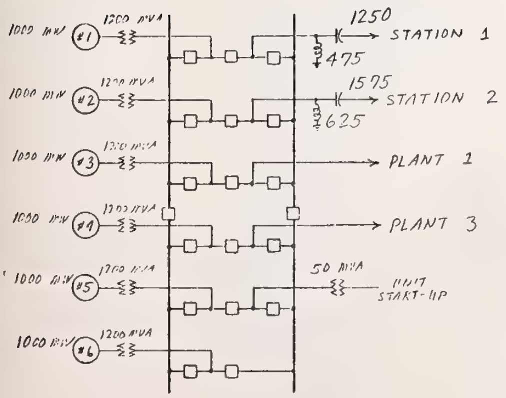


GILLETTE COMPLEX

PLANT 1



KANSAS CITY SUBSTATION



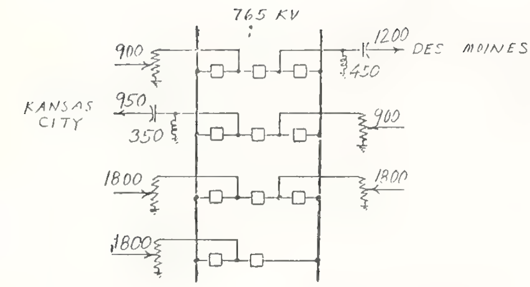
GILLETTE COMPLEX

PLANT 2

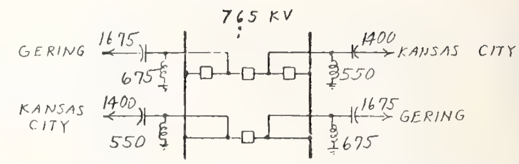
NOTES:

1. All reactor and capacitor values in mvar.
2. Generator unit transformers: 22/765 Kv. 1ϕ, total mva shown.
3. Start-up transformers: 22/765 Kv. 1ϕ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.

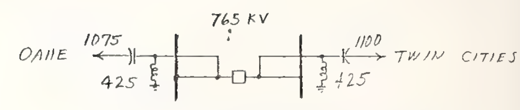
NCPS
EASTERN EHV SYSTEM
CASE 20D7-B02



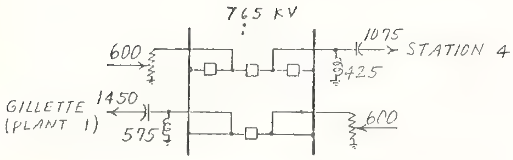
MONTGOMERY SUBSTATION



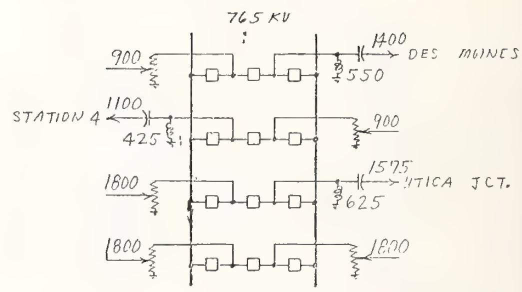
SWITCHING STATION NO. 3



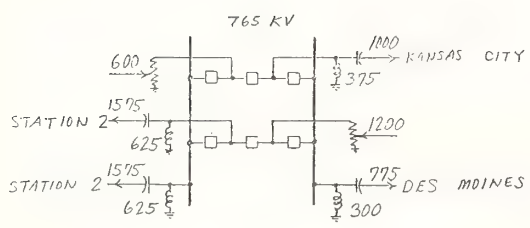
SWITCHING STATION NO. 4



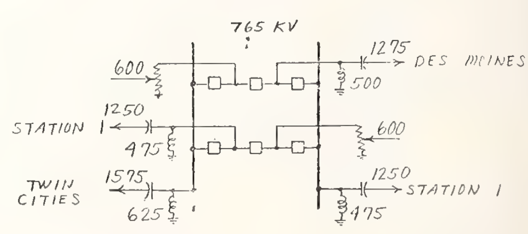
OAHE SUBSTATION



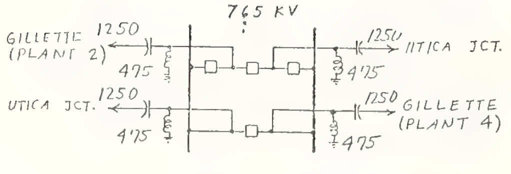
TWIN CITIES SUBSTATION



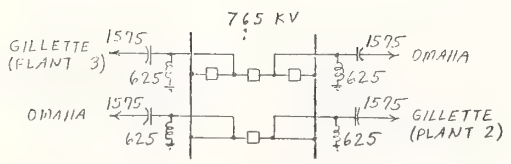
OMAHA SUBSTATION



UTICA JCT. SUBSTATION



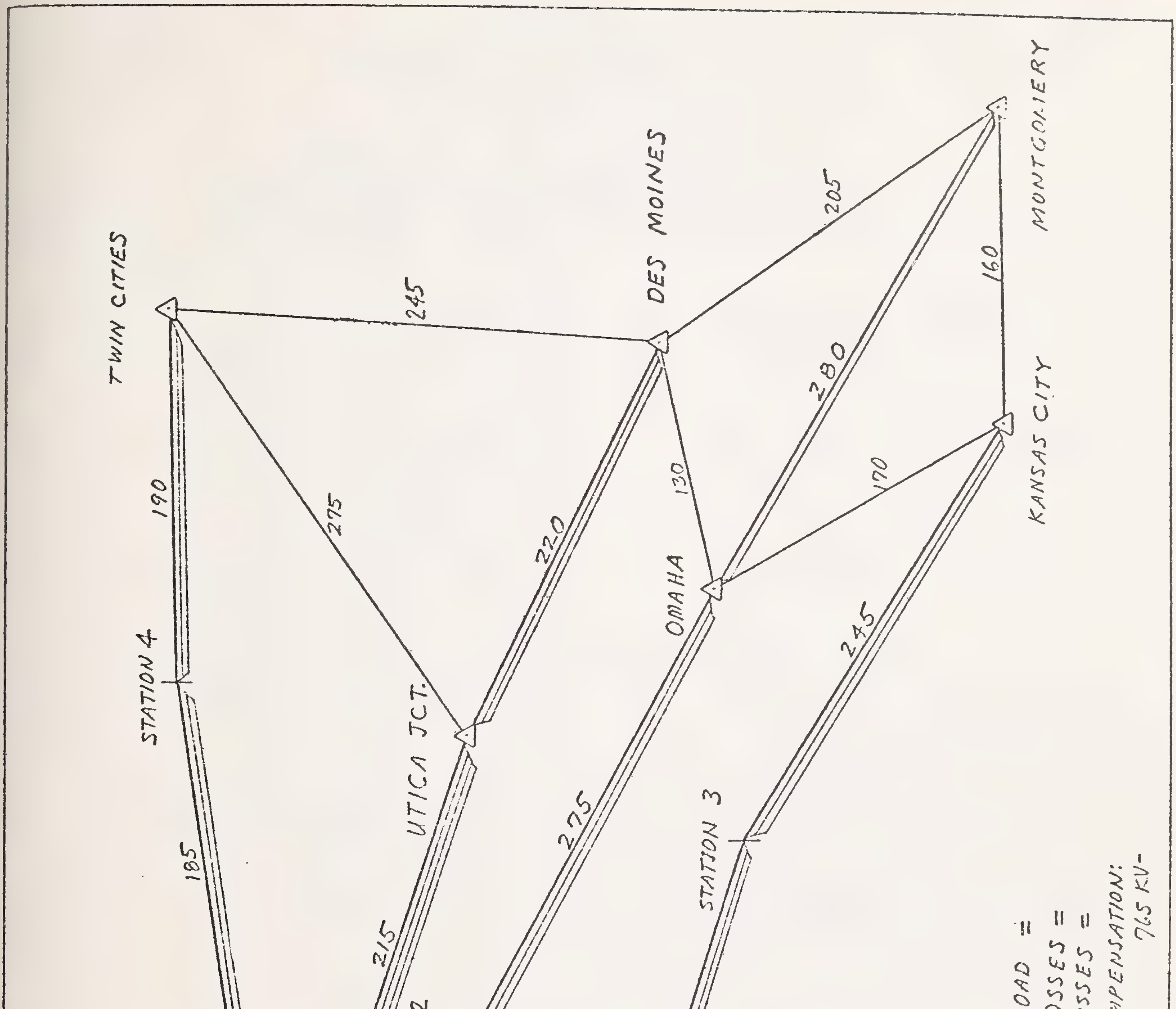
SWITCHING STATION NO. 1



SWITCHING STATION NO. 2

NOTES:

1. All reactor and capacitor values in mvar.
2. Generator unit transformers: 22/765 Kv, 1ϕ, total mva shown.
3. Start-up transformers: 22/765 Kv, 1ϕ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.



GILLETTE
OAHE
STATION 4
TWIN CITIES
STATION 1
UTICA JCT.
DES MOINES
STATION 2
OMAHA
MONTGOMERY
GERING
STATION 3
KANSAS CITY
255
185
190
215
215
275
275
220
245
275
130
280
205
205
170
160
295
245
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 40D7-B03
TOTAL LOAD =
MW LOSSES =
MVAR LOSSES =
LINE COMPENSATION:
500KV-
765 KV-
Recorded:
Run:

770 05/17/71

NCPS
EASTERN EHV SYSTEM
CASE 4007-803

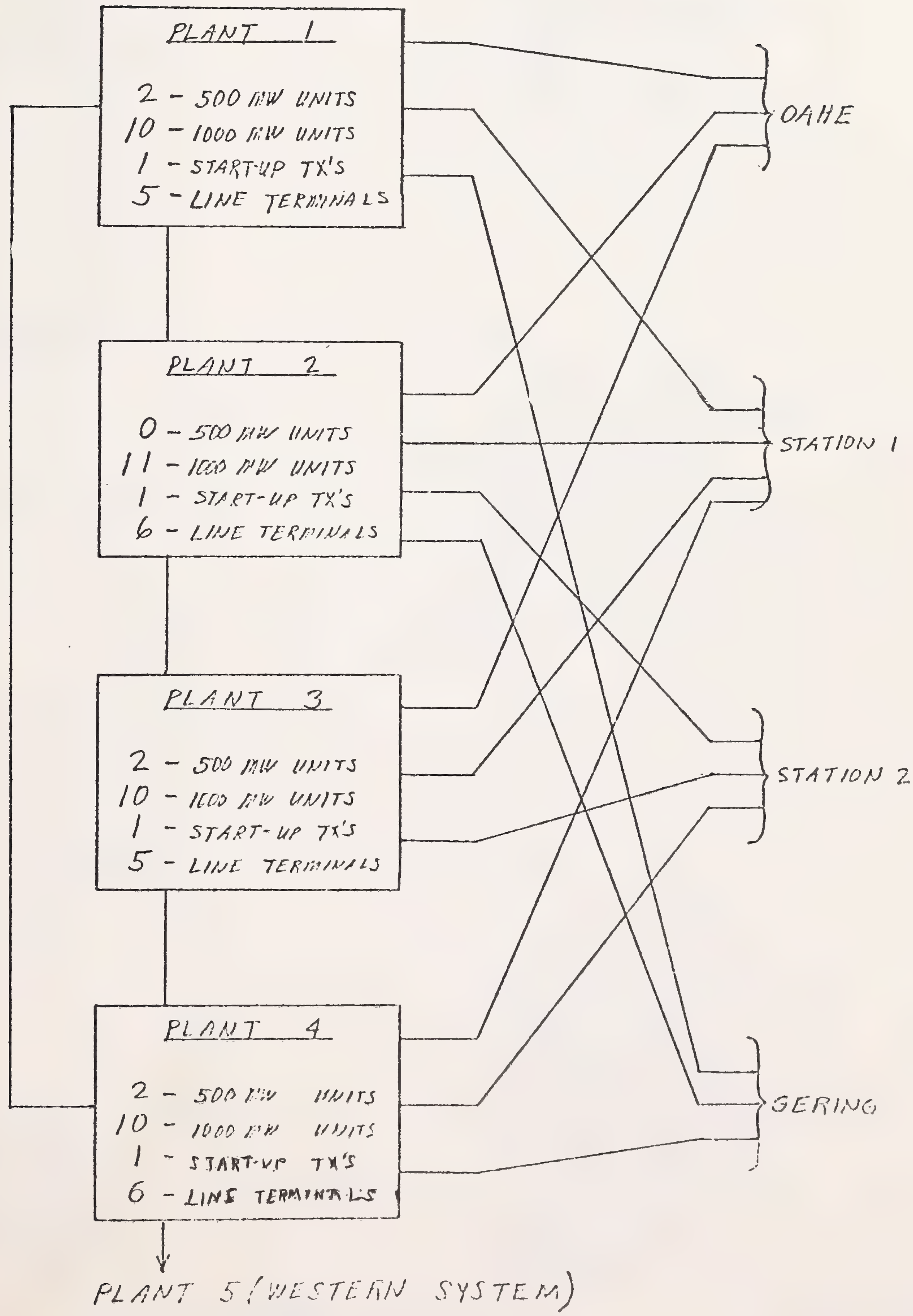
765 KV TRANSMISSION LINE DATA

TERMINAL 1 - TERMINAL 2	MILES	NUMBER OF LINES	TOTAL MILES	% SERIES COMP.
DES MOINES - MONTGOMERY	205.0	1	205.0	80
" " - OMAHA	130.0	1	130.0	80
" " - TWIN CITIES	245.0	1	245.0	80
" " - UTICA JCT.	220.0	3	660.0	80
GERING - GILLETTE	205.0	3	615.0	80
" - STATION 3	295.0	3	885.0	80
GILLETTE - OAHE	255.0	3	765.0	80
" - STATION 1	215.0	4	860.0	80
" - STATION 2	275.0	3	825.0	80
KANSAS CITY - MONTGOMERY	160.0	1	160.0	80
" " - OMAHA	170.0	1	170.0	80
" " - STATION 3	245.0	3	735.0	80
MONTGOMERY - OMAHA	280.0	2	560.0	80
OAHE - STATION 4	185.0	3	555.0	80
OMAHA - STATION 2	275.0	3	825.0	80
STATION 1 - UTICA JCT.	215.0	4	860.0	80
STATION 4 - TWIN CITIES	190.0	3	570.0	80
TWIN CITIES - UTICA JCT.	275.0	1	275.0	80
GILLETTE COMPLEX TIES	8.0	3	24.0	0
GILLETTE COMPLEX TIES	24.0	1	24.0	0
TOTAL MILEAGE (ALL 4-1272 MCM)			9948.0	

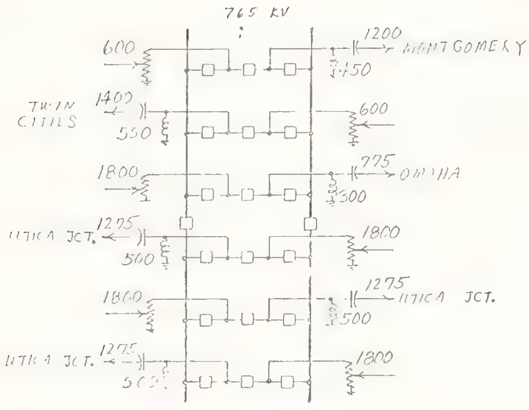
TLS 05/06/71
REV. 06/25/71 TLS

NCPS
EASTERN EHV SYSTEM
CASE 4007-803

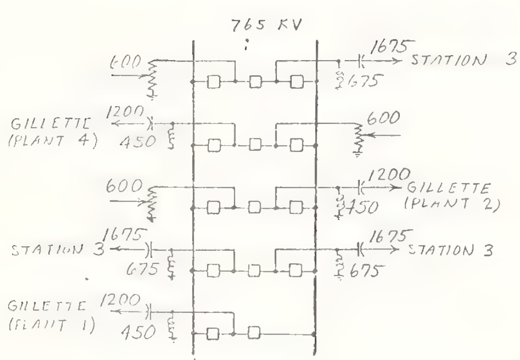
GILLETTE COMPLEX



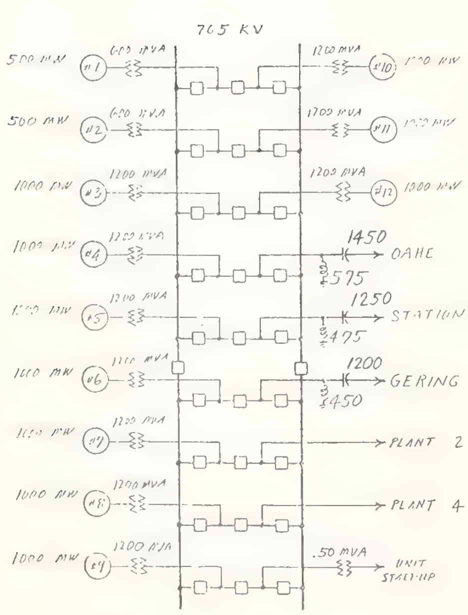
NCPS
EASTERN EHV SYSTEM
CASE 40D7-803



DES MOINES SUBSTATION

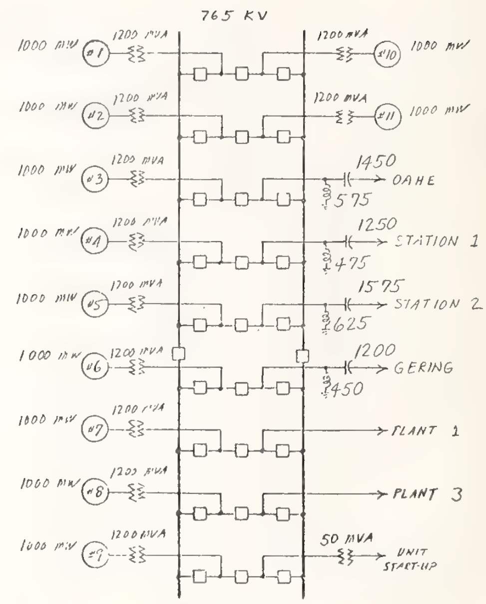


GERING SUBSTATION



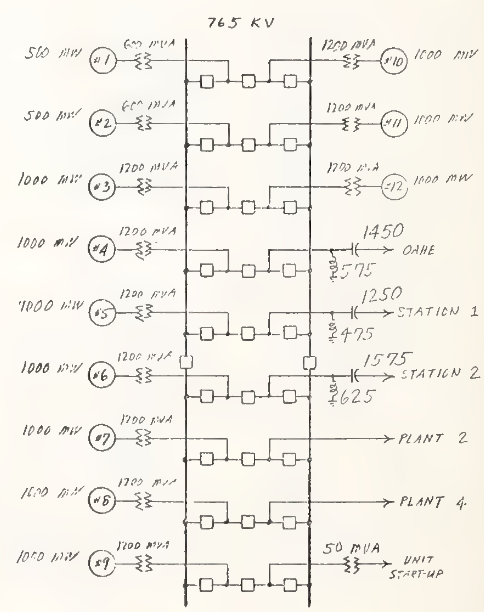
GILLETTE COMPLEX

PLANT 1



GILLETTE COMPLEX

PLANT 2



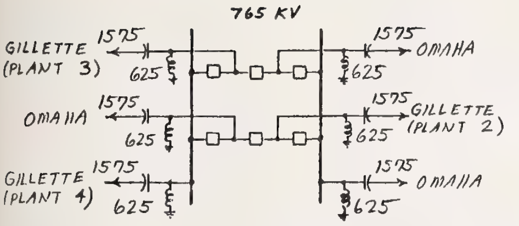
GILLETTE COMPLEX

PLANT 3

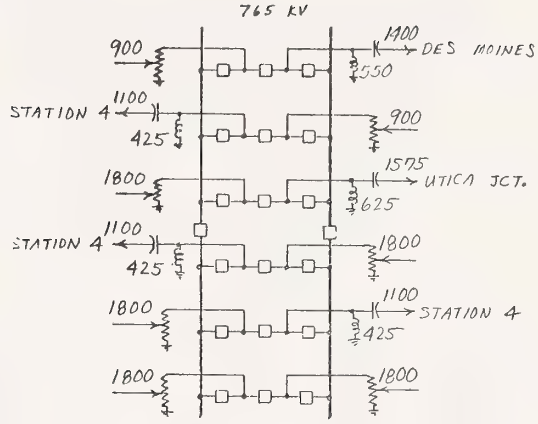
NOTES:

1. All reactor and capacitor values in mvar.
2. Generator unit transformers: 22/765 Kv. 1ϕ, total mva shown.
3. Start-up transformers: 22/765 Kv, 1ϕ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.

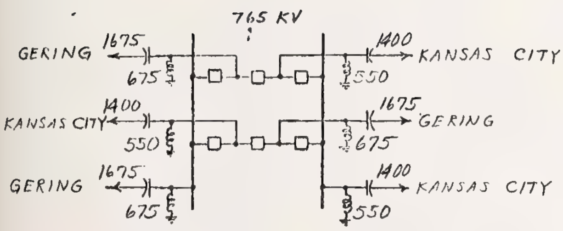
NCPS
EASTERN EHV SYSTEM
CASE 40D7-B03



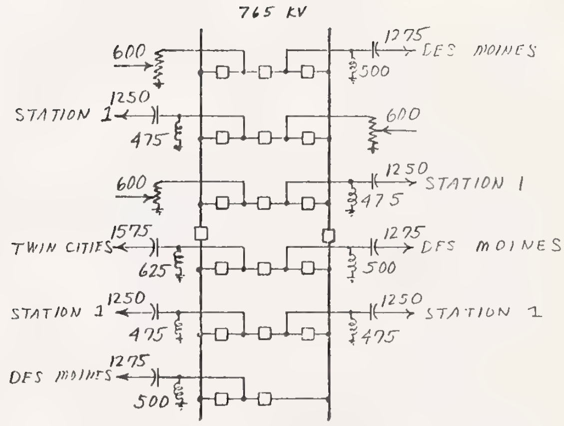
SWITCHING STATION NO. 2



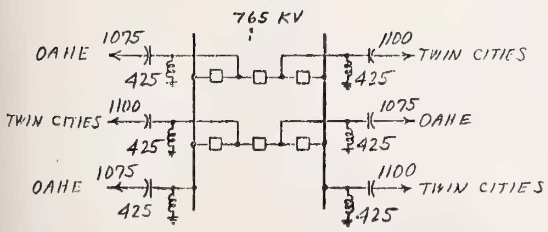
TWIN CITIES SUBSTATION



SWITCHING STATION NO. 3



UTICA JCT. SUBSTATION

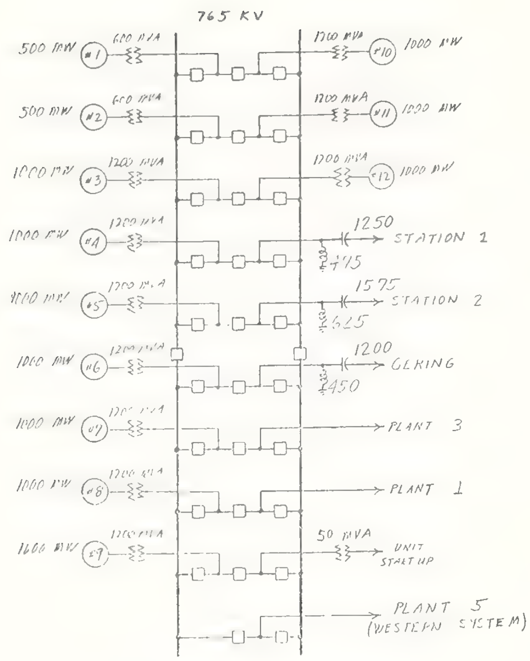


SWITCHING STATION NO. 4

NOTES:

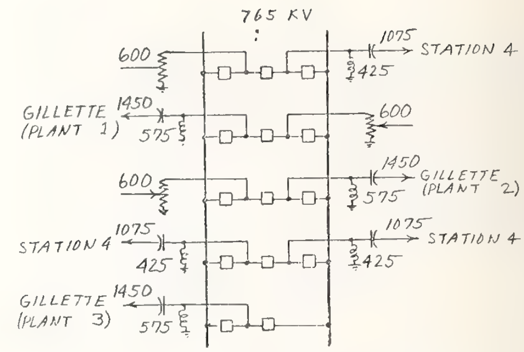
1. All reactor and capacitor values in mvar.
2. Generator unit transformers: 22/765 Kv, 1Φ, total mva shown.
3. Start-up transformers: 22/765 Kv, 1Φ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.

NCPS
EASTERN EHV SYSTEM
CASE 4007-B03

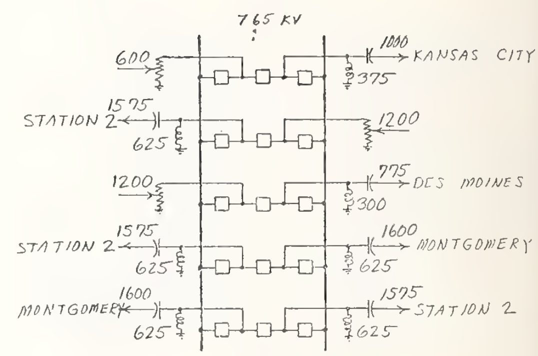


GILLETTE COMPLEX

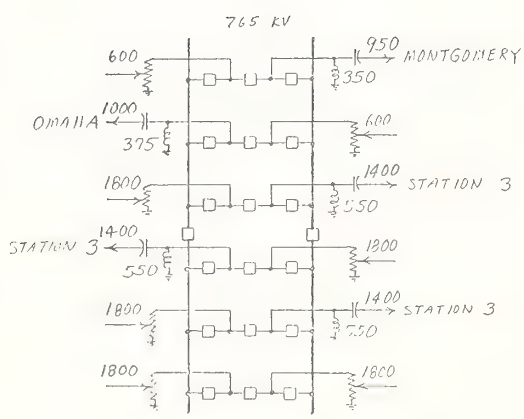
PLANT 4



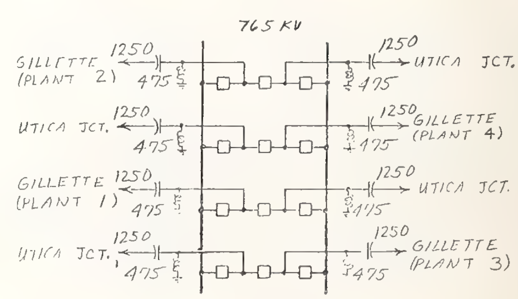
OAHE SUBSTATION



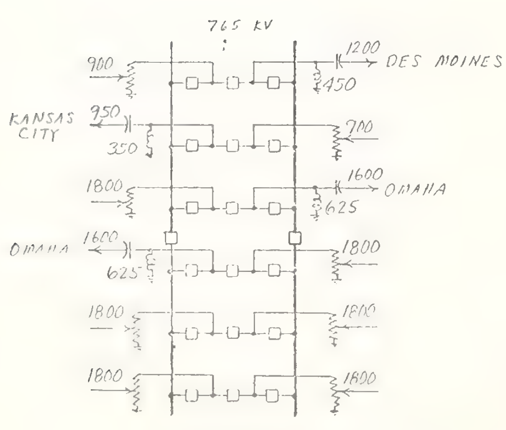
OMAHA SUBSTATION



KANSAS CITY SUBSTATION



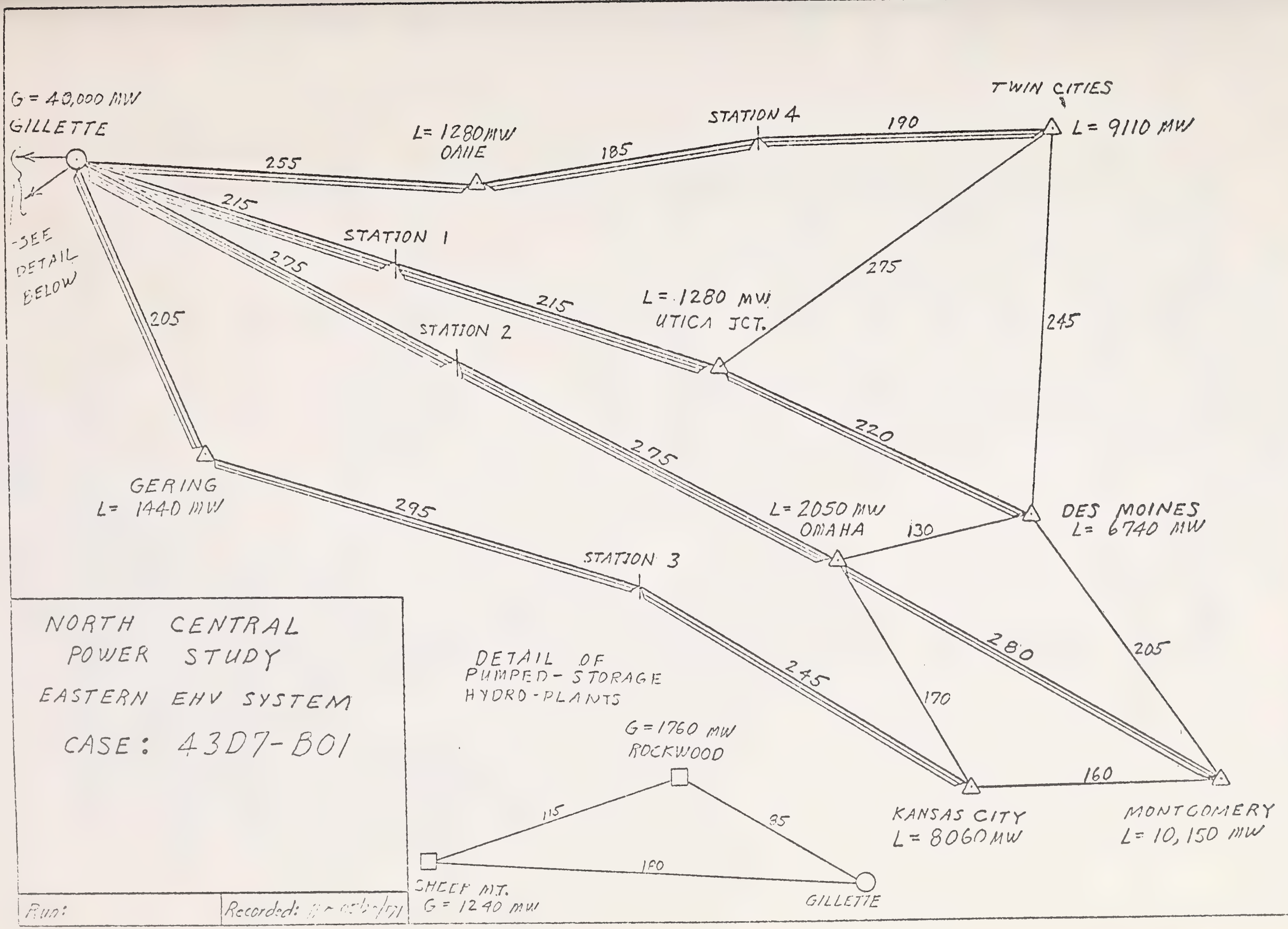
SWITCHING STATION NO. 1



MONTGOMERY SUBSTATION

NOTES:

1. All reactor and capacitor values in mvar.
2. Generator unit transformers: 22/765 Kv, 1Φ, total mva shown.
3. Start-up transformers: 22/765 Kv, 1Φ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.


G = 40,000 MW
GILLETTE
-SEE DETAIL BELOW
255
L= 1280 MW
OAHE
185
STATION 4
190
TWIN CITIES
L = 9110 MW
215
STATION 1
215
275
L= 1280 MW
UTICA JCT.
275
245
205
STATION 2
275
220
GERING
L= 1440 MW
295
L= 2050 MW
OMAHA
130
DES MOINES
L= 6740 MW
STATION 3
280
205
245
170
160
KANSAS CITY
L= 8060 MW
MONTGOMERY
L= 10,150 MW
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-B01
DETAIL OF
PUMPED-STORAGE
HYDRO-PLANTS
G=1760 MW
ROCKWOOD
115
85
180
SHEEP MT.
G = 1240 MW
GILLETTE
Run:
Recorded:

770 05/20/71

NCPS
EASTERN EHV SYSTEM
CASE 43D7-B01
765 KV TRANSMISSION LINE DATA

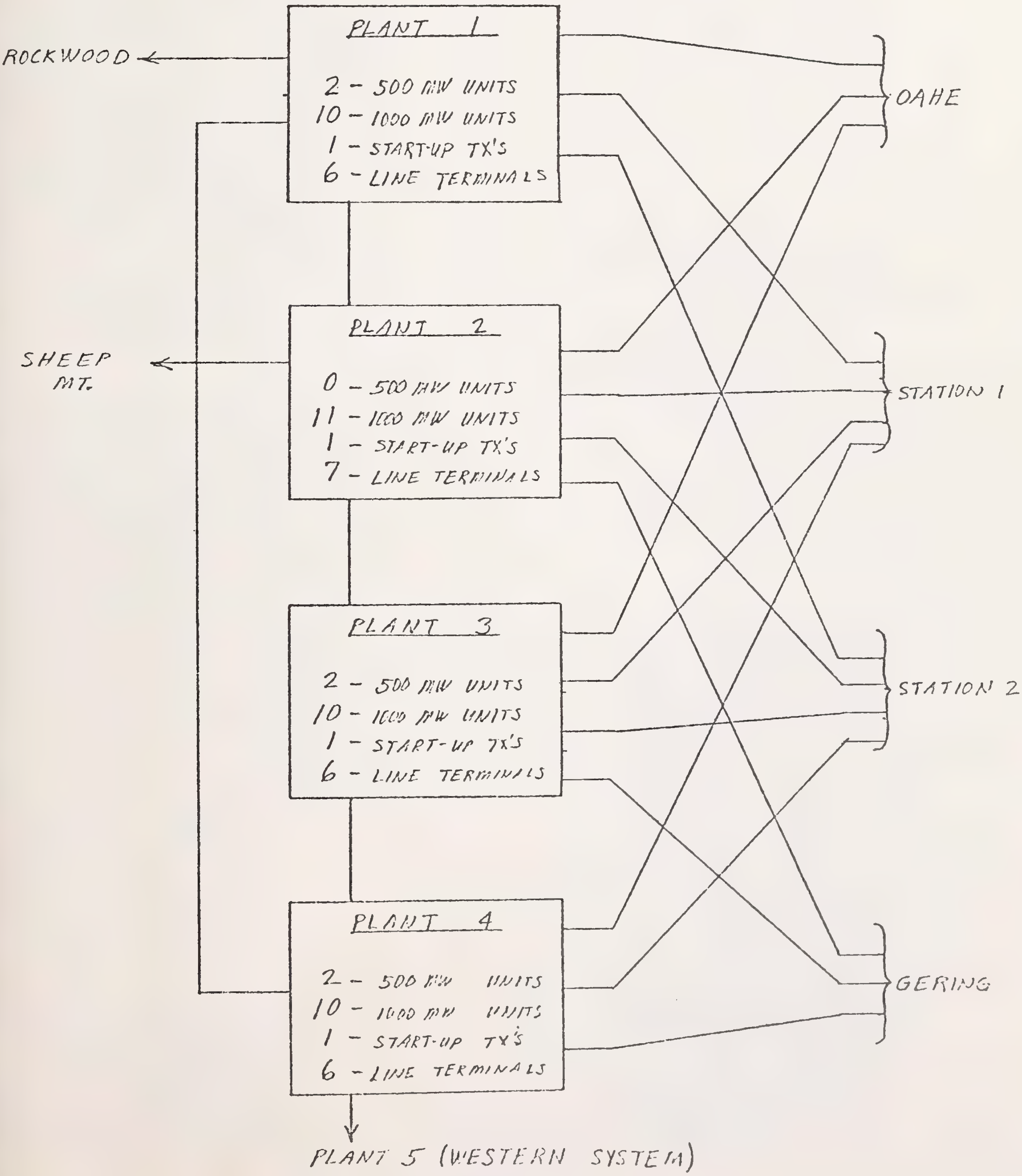
TERMINAL 1 - TERMINAL 2		MILES	NUMBER OF LINES	TOTAL MILES	% SERIES COMP.
DES MOINES	- MONTGOMERY	205.0	1	205.0	80
" "	- OMAHA	130.0	1	130.0	80
" "	- TWIN CITIES	245.0	1	245.0	80
" "	- UTICA JCT.	220.0	3	660.0	80
GERING	- GILLETTE	205.0	3	615.0	80
"	- STATION 3	295.0	3	885.0	80
GILLETTE	- OAHE	255.0	3	765.0	80
"	- ROCKWOOD	85.0		85.0	
"	- SHEEP MT.	180.0		180.0	
"	- STATION 1	215.0	4	860.0	80
"	- STATION 2	275.0	4	1100.0	80
KANSAS CITY	- MONTGOMERY	160.0	1	160.0	80
" "	- OMAHA	170.0	1	170.0	80
" "	- STATION 3	245.0	3	735.0	80
MONTGOMERY	- OMAHA	280.0	3	840.0	80
OAHE	- STATION 4	185.0	3	555.0	80
OMAHA	- STATION 2	275.0	4	1100.0	80
ROCKWOOD	- SHEEP MT.	115.0		115.0	80
STATION 1	- UTICA JCT.	215.0	4	860.0	80
STATION 4	- TWIN CITIES	190.0	3	570.0	80
TWIN CITIES	- UTICA JCT.	275.0	1	275.0	80
GILLETTE COMPLEX TIES		8.0	4	32.0	0
GILLETTE COMPLEX TIES		24.0	1	24.0	0
TOTAL MILEAGE				11,166.0	

(ALL LINES HAVE 4-1272 MCM CONDUCTORS)

TJE 05/20/71
REV. 06/25/71 TJE

NCPS
EASTERN EHV SYSTEM
CASE 43D7-B01

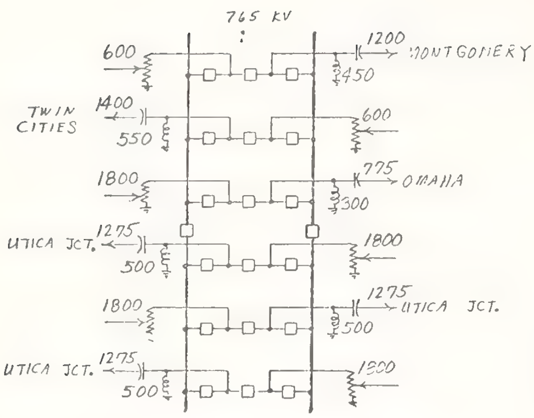
GILLETTE COMPLEX



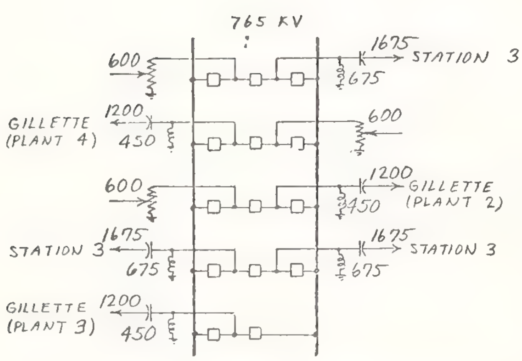
NCPS

EASTERN EHV SYSTEM

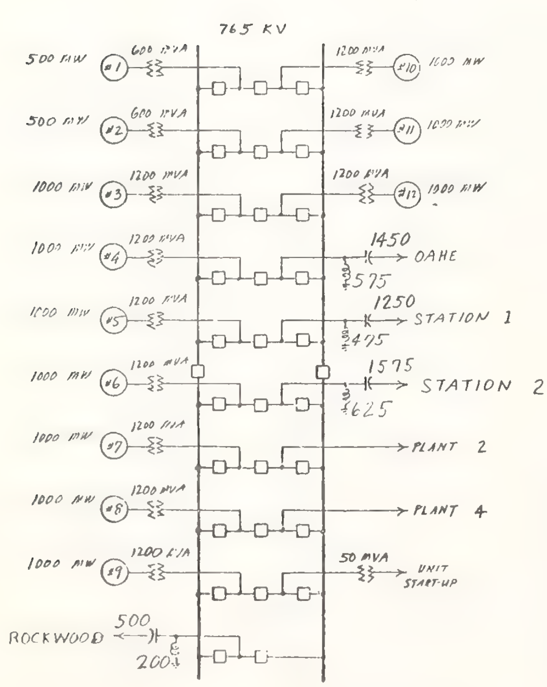
CASE 43D7-B01



DES MOINES SUBSTATION

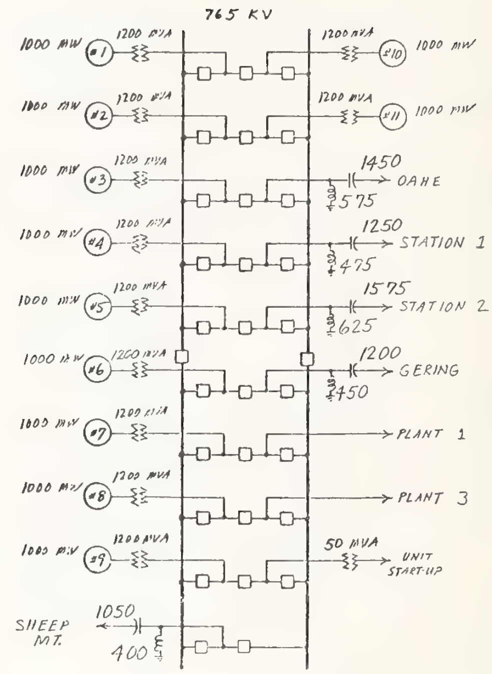


GERING SUBSTATION



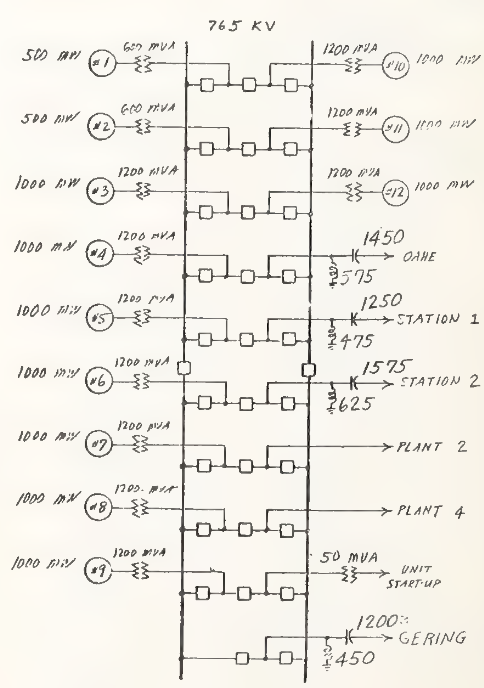
GILLETTE COMPLEX

PLANT 1



GILLETTE COMPLEX

PLANT 2



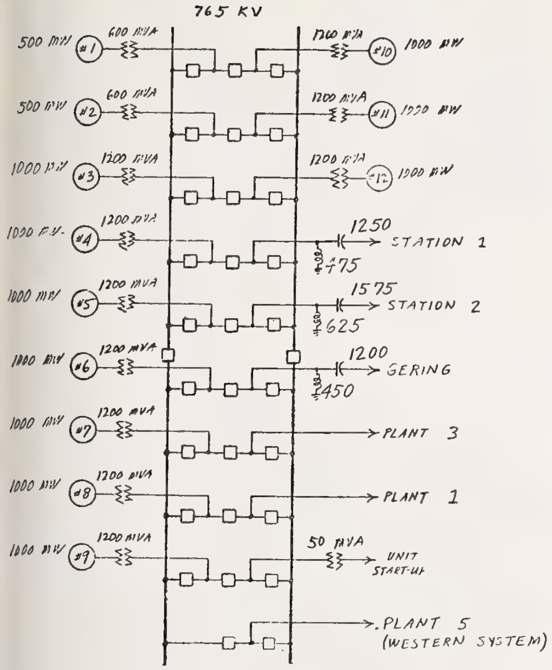
GILLETTE COMPLEX

PLANT 3

NOTES:

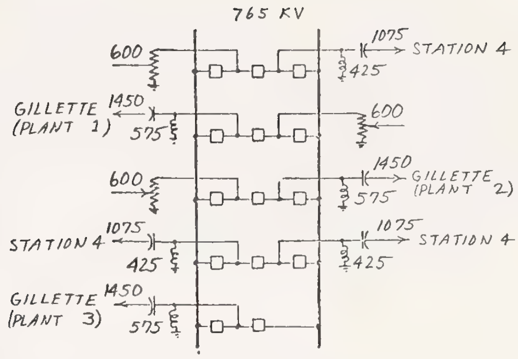
1. All reactor and capacitor values in mVar.
2. Generator unit transformers: 22/765 Kv, 1ϕ, total mva shown.
3. Start-up transformers: 22/765 Kv, 1ϕ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.

NCPS
EASTERN EHV SYSTEM
CASE 4307-801

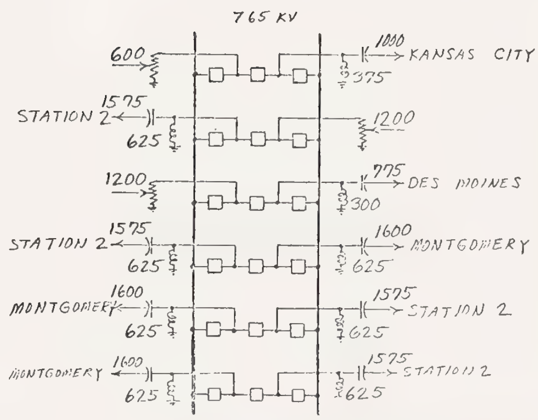


GILLETTE COMPLEX

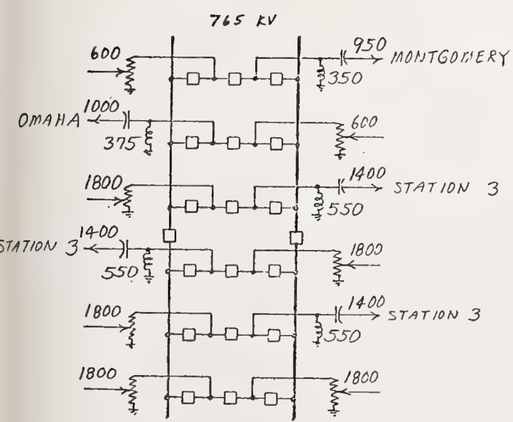
PLANT 4



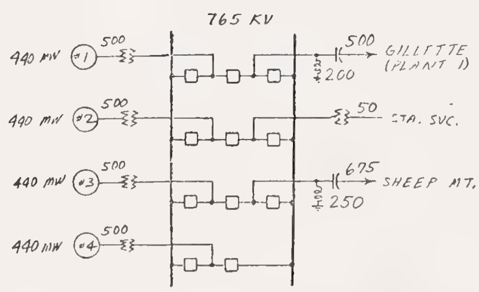
OAHE SUBSTATION



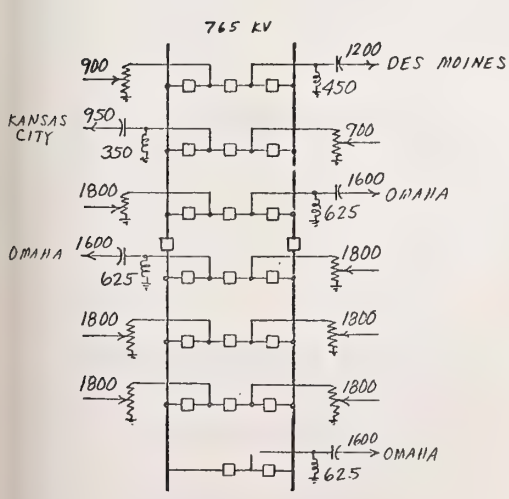
OMAHA SUBSTATION



KANSAS CITY SUBSTATION



ROCKWOOD POWER PLANT

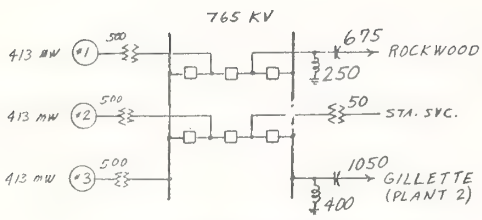


MONTGOMERY SUBSTATION

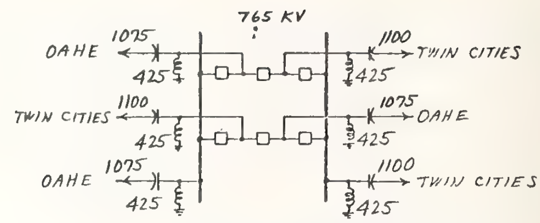
NOTES:

1. All reactor and capacitor values in mVar.
2. Generator unit transformers: 22/765 Kv, 1 ϕ, total mva shown.
3. Start-up transformers: 22/765 Kv, 1 ϕ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.

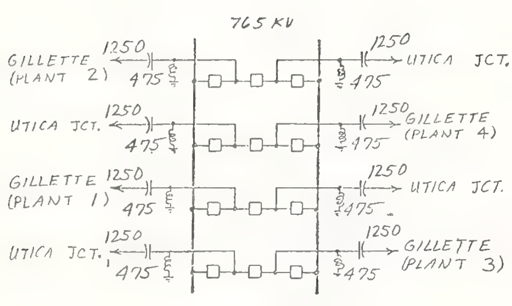
NCPS
EASTERN EHV SYSTEM
CASE 43D7-B01



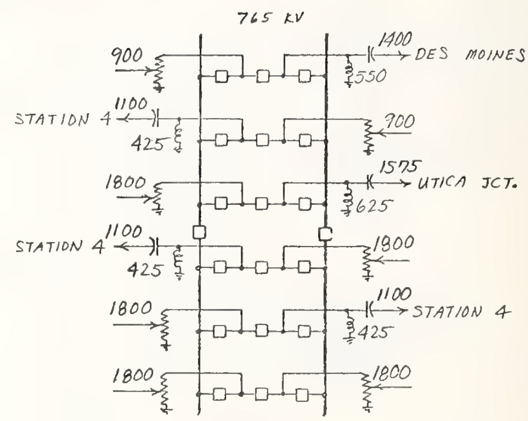
SHEEP MT. POWERPLANT



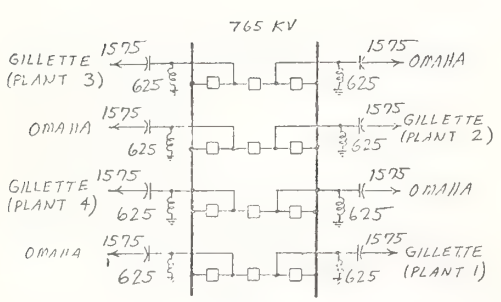
SWITCHING STATION NO. 4



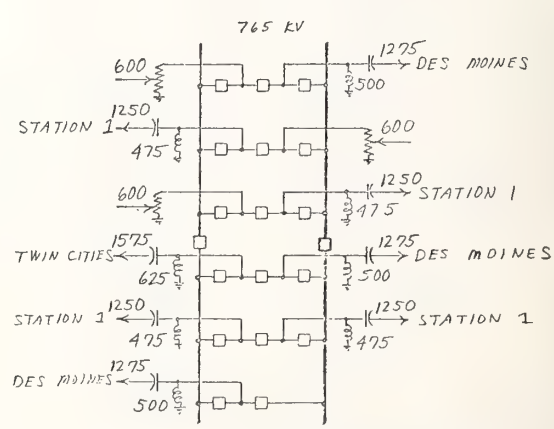
SWITCHING STATION NO. 1



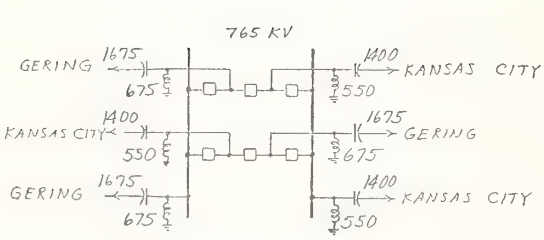
TWIN CITIES SUBSTATION



SWITCHING STATION NO. 2



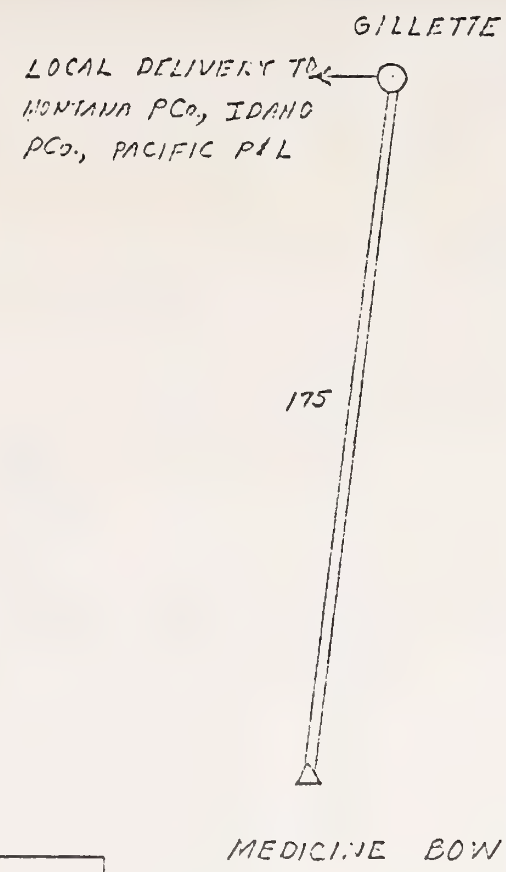
UTICA JCT. SUBSTATION



SWITCHING STATION NO. 3

NOTES:

1. All reactor and capacitor values in mvar.
2. Generator unit transformers: 22/765 Kv, 1ϕ, total mva shown.
3. Start-up transformers: 22/765 Kv, 1ϕ, total mva shown.
4. Substation step-down transformer ratings are mva and all are voltage rated 765/345 Kv.



NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE: 01 W5-B01
BASED ON CASE:

[illegible]	Recorded:

RJ 0?/22/71

REV. 06/25/71 7ZO

NCPS

WESTERN EHV SYSTEM
CASE 01W5-B01

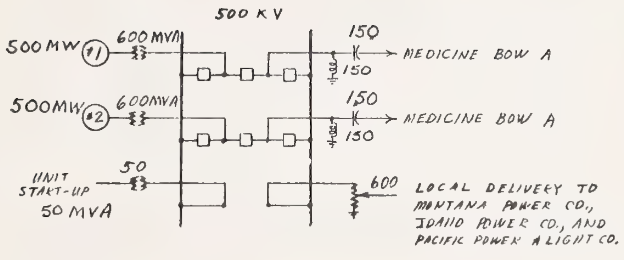
500 KV TRANSMISSION LINE DATA

TERMINAL 1	-	TERMINAL 2	MILES	NUMBER OF LINES	TOTAL MILES	% SERIES COMP.
GILLETTE	-	MEDICINE BOW A	175.0	2	350.0	70
GILLETTE	-	MEDICINE BOW B	175.0	0	0.0	70
MEDICINE BOW A	-	MEDICINE BOW B	0	0	0.0	0
TOTAL MILEAGE (ALL 3-1192.5 MCM)					350.0	

NCPS

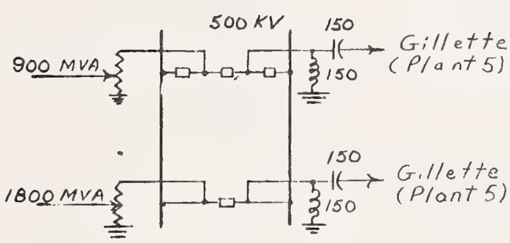
WESTERN EHV SYSTEM

CASE 01W5-B01



GILLETTE COMPLEX

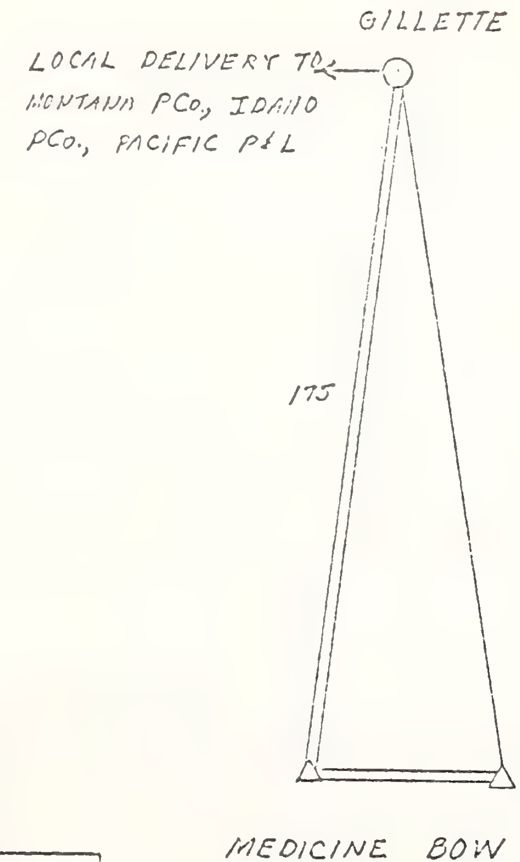
PLANT 5



MEDICINE BOW

SUBSTATION A

NOTES: 1) ALL REACTOR AND CAPACITOR VALUES IN MVAR.
2) TRANSFORMER RATINGS ARE MVA AND ALL ARE VOLTAGE RATED 500/345 KV.



NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE: 03W5-B01
BASED ON CASE:

Run: | Recorded:

RJ. 06/22/71 NCPS

REV. 07/25/71 ??? WESTERN EHV SYSTEM

CASE 03W5 - B01

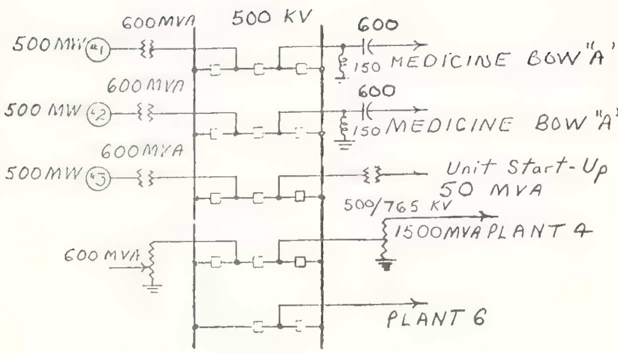
500 KV TRANSMISSION LINE DATA

TERMINAL 1 - TERMINAL 2	MILES	No. of Lines	Total Miles	% Series Comp.
GILLETTE - MEDICINE BOW A	175.0	2	350.0	70
GILLETTE - MEDICINE BOW B	175.0	1	175.0	70
MEDICINE BOW A - MEDICINE BOW B	0	2	0	0
TOTAL MILEAGE (ALL 3-1192.5 MCM)			525.0	
GILLETTE COMPLEX TIES - 500KV	8.0	1	8.0	
TOTAL 500 KV			533.0	

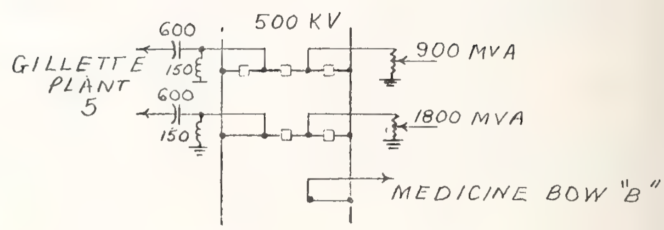
PLUS 8 MILES OF 765 KV LINE PLANT 5 TO PLANT 4.
(WITH 4-1272 MCM.)

NCPS

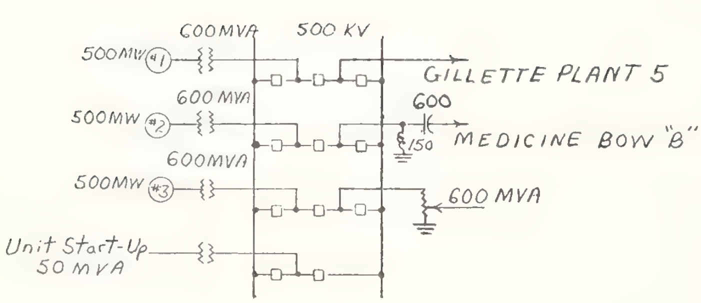
WESTERN EHV SYSTEM
CASE 03W5-B01



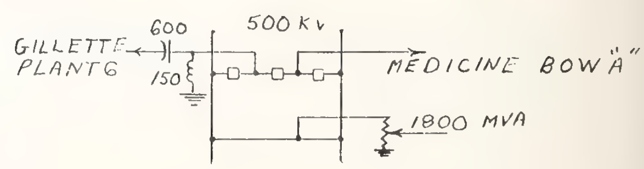
GILLETTE COMPLEX
PLANT 5



MEDICINE BOW
SUBSTATION A

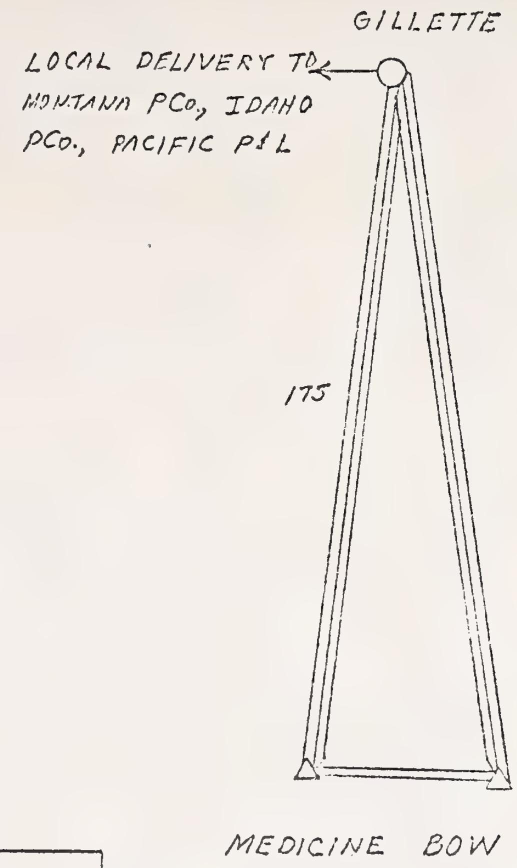


GILLETTE COMPLEX
PLANT 6



MEDICINE BOW
SUBSTATION B

NOTES: 1) ALL REACTOR AND CAPACITOR VALUES IN MVAR.
2) TRANSFORMER RATINGS SHOWN ARE MVA AND ALL ARE VOLTAGE RATED 500/34.5 KV.



NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE : 10W5-B01
BASED ON CASE:

Run:	Recorded:

RJ 06/22/71

REV. 06/25/71 [illegible]

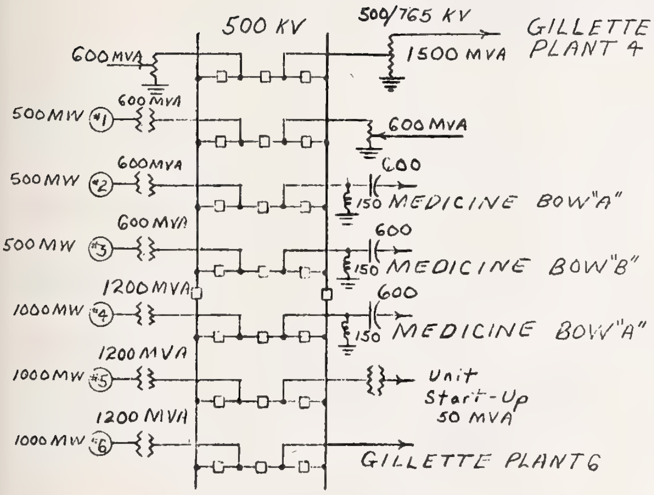
NCPS

WESTERN EHV SYSTEM
CASE 10W5-B01

500 KV TRANSMISSION LINE DATA

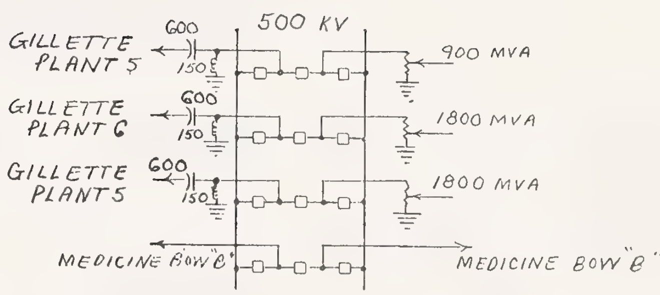
TERMINAL 1 — TERMINAL 2	MILES	No. of Lines	Total Miles	% Series Comp
GILLETTE - MEDICINE BOW A	175.0	3	525.0	70
GILLETTE - MEDICINE BOW B	175.0	3	525.0	70
MEDICINE BOW A - MEDICINE BOW B	0	2	0	0
TOTAL MILEAGE (ALL 3-1192.5 MCM)			1050.0	
GILLETTE COMPLEX TIES - 500 KV	8.0	1	8.0	
TOTAL 500 KV			1058.0	

PLUS 8 MILES OF 765-KV LINE PLANT 5 TO PLANT 4.
(WITH 4-1272 MCM.)



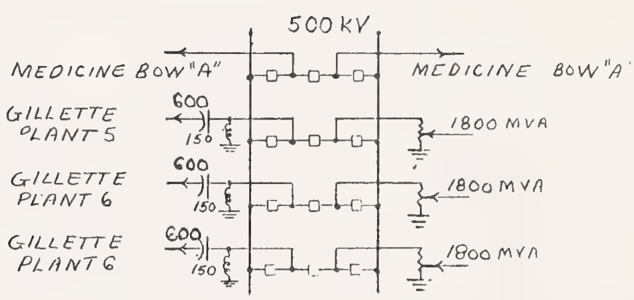
GILLETTE COMPLEX

PLANT 5



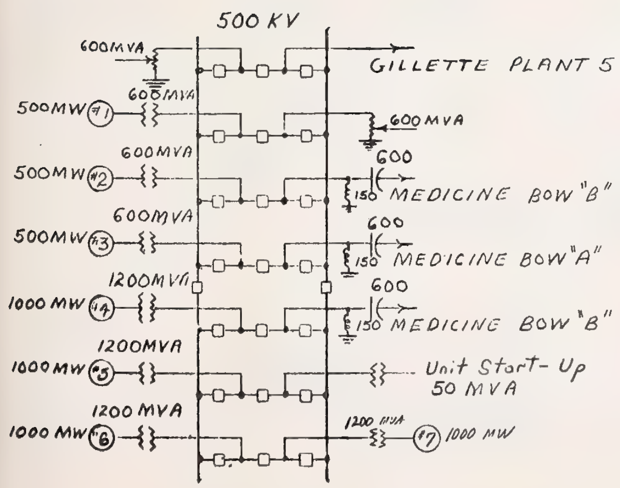
MEDICINE BOW

SUBSTATION A



MEDICINE BOW

SUBSTATION B



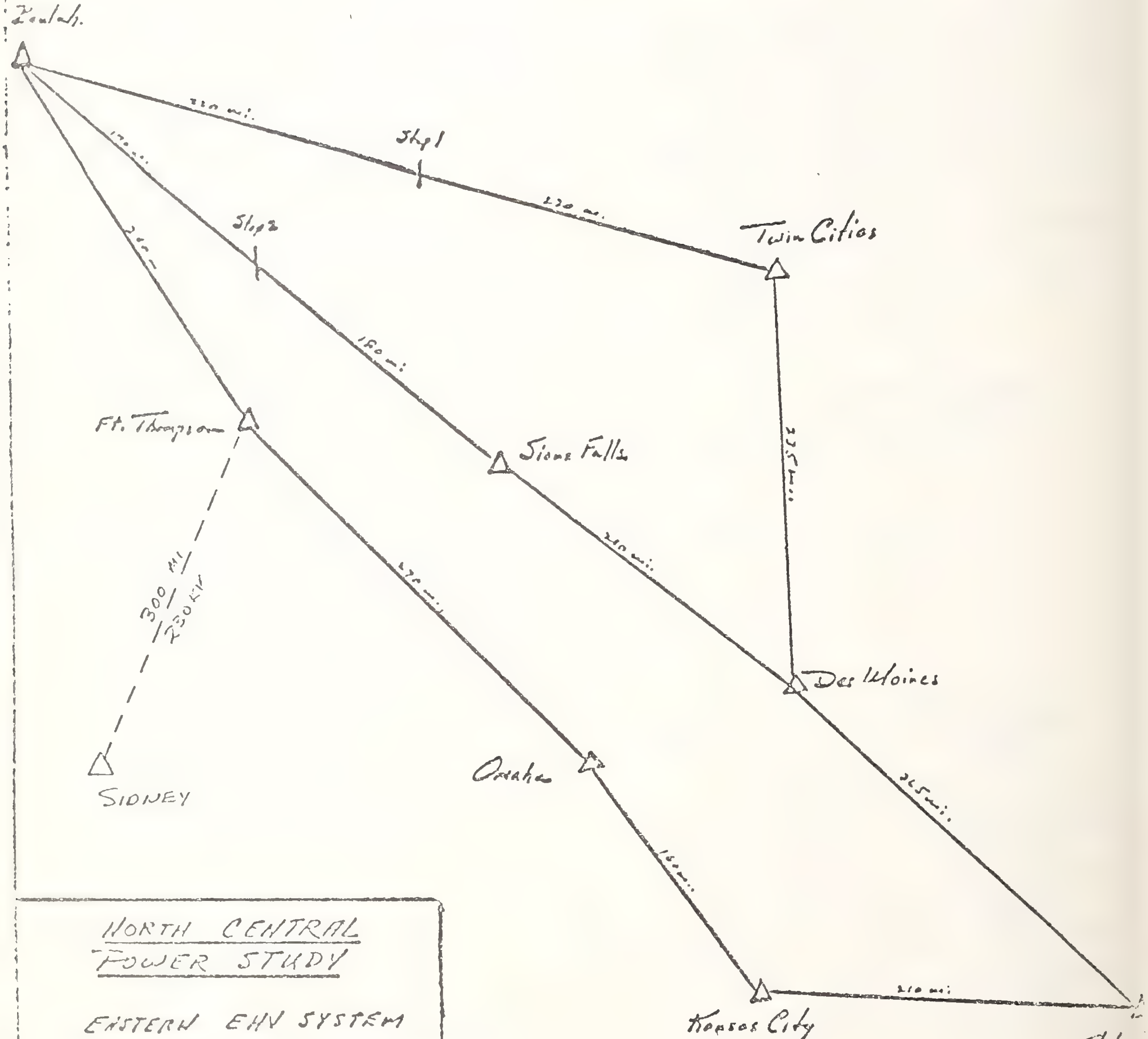
GILLETTE COMPLEX

PLANT 6

NOTES: 1) ALL REACTOR AND CAPACITOR VALUES IN MVAR.
2) TRANSFORMER RATINGS SHOWN ARE MVA AND ALL ARE VOLTAGE RATED 500/345 KV.

SAF 4/7/71
4/21/71

NCPS
EASTERN EHV SYSTEM
CASE NO 03N5-B02
RING BUS SCHEME



NORTH CENTRAL
POWER STUDY

EASTERN EHV SYSTEM

Level 3000 MW
Voltage Level 500 KV
Plan N

Case. 03N5-B02
Run Date By
Recorded Date By

SAF 4/5/71 NCPS.
TLD 4/21/71 EASTERN EHV SYSTEM
CASE NO. 03N5-B02

500 KV TRANSMISSION LINE DATA

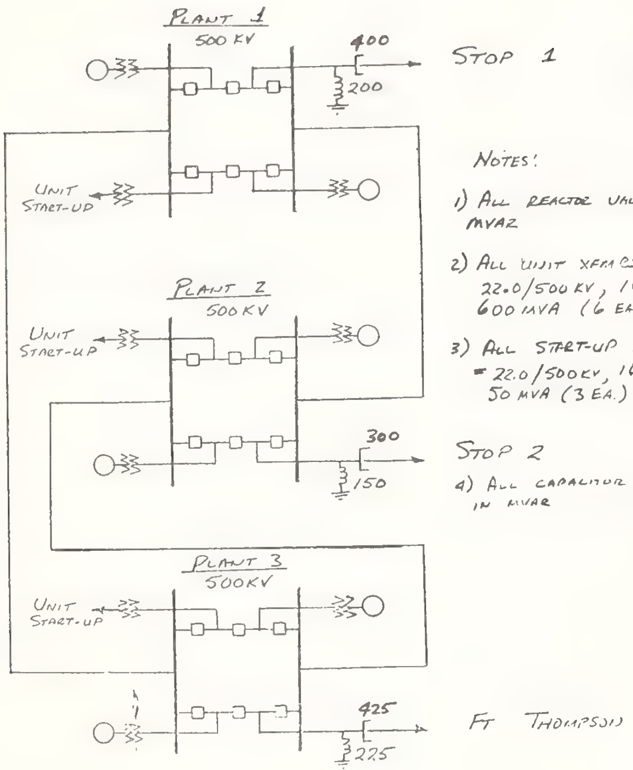
TERMINAL 1	TERMINAL 2	MILAGE	CONDUCTOR NO. & SIZE
BEULAH –	STOP 1	220.0	2-2167 MCM ACSR
BEULAH –	STOP 2	170.0	
BEULAH –	FT. THOMPSON	240.0	
STOP 1 –	TWIN CITIES	220.0	
TWIN CITIES –	DES MOINES	235.0	
STOP 2 –	SIOUX FALLS.	180.0	
SIOUX FALLS –	DES MOINES.	210.0	
FT. THOMPSON –	OMAHA	270.0	
OMAHA –	KANSAS CITY.	160.0	
KANSAS CITY –	ST. LOUIS.	210.0	
DES MOINES –	ST. LOUIS	265.0	2-2167 MCM ACSR

TOTAL MILAGE = 2,380.0

230 KV TRANSMISSION LINE DATA

FT. THOMPSON – SIDNEY 300 MI 1-954 MCM ACSR

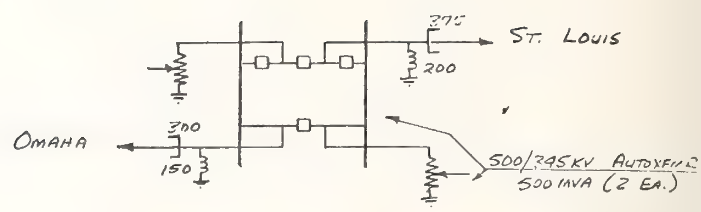
NCPS
EASTERN EHV SYSTEM
CASE: 03NS-B02



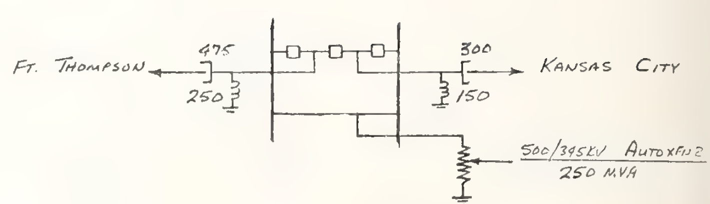
NOTES:

1) ALL REACTOR VALUES IN MVAR
2) ALL UNIT XFMRS = 22.0/500 KV, 1Ø, 600 MVA (6 EA.)
3) ALL START-UP XFMRS = 22.0/500KV, 1Ø, 50 MVA (3 EA.)
4) ALL CAPACITOR VALUE IN MVAR

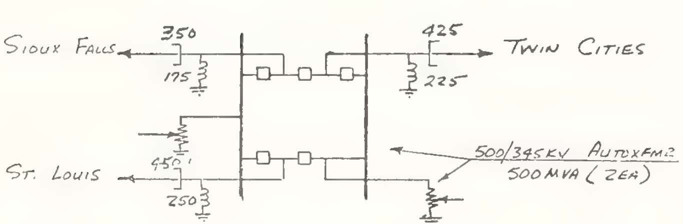
BEULAH COMPLEX



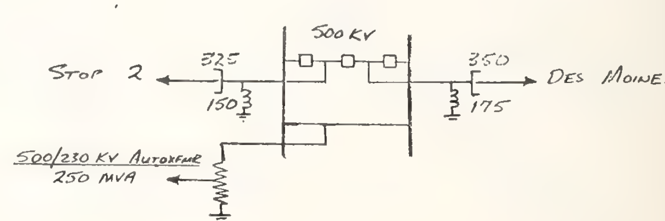
KANSAS CITY SUBSTATION



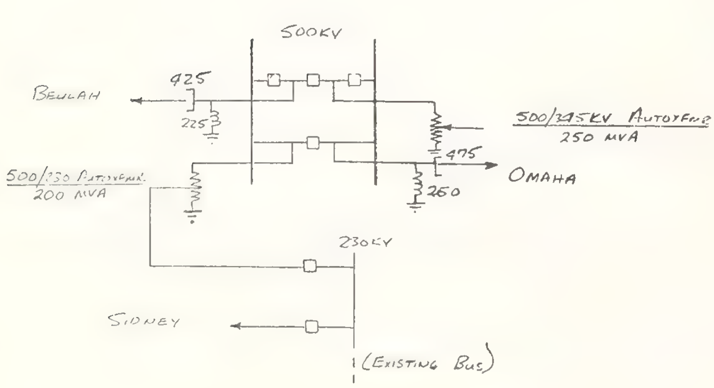
OMAHA SUBSTATION



DES MOINES SUBSTATION



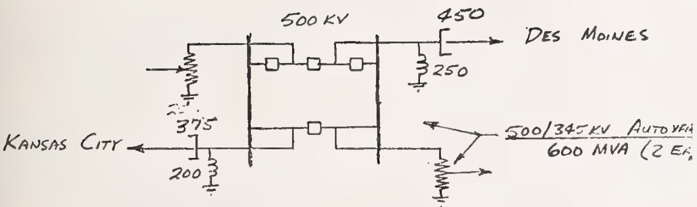
SIOUX FALLS SUBSTATION



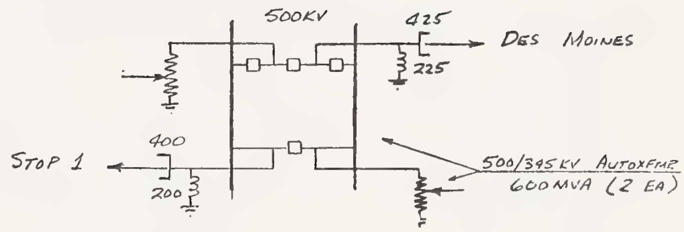
FT THOMPSON SUBSTATION

NOTE: 1) ALL REACTOR VALUES IN MVAR
2) ALL CAPACITOR VALUES IN MVAR

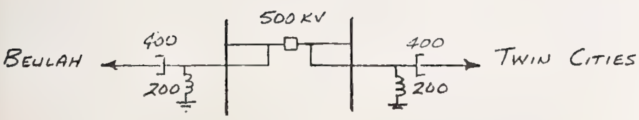
NCPS
EASTERN EHV SYSTEM
CASE: 03N5-B02



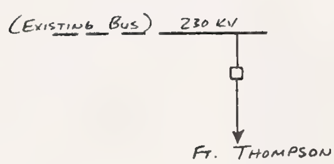
ST. LOUIS SUBSTATION



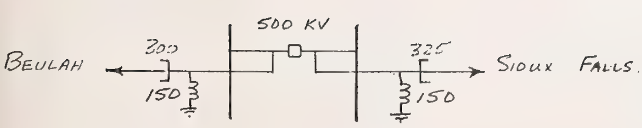
TWIN CITIES SUBSTATION



STOP 1 SWITCHING STATION



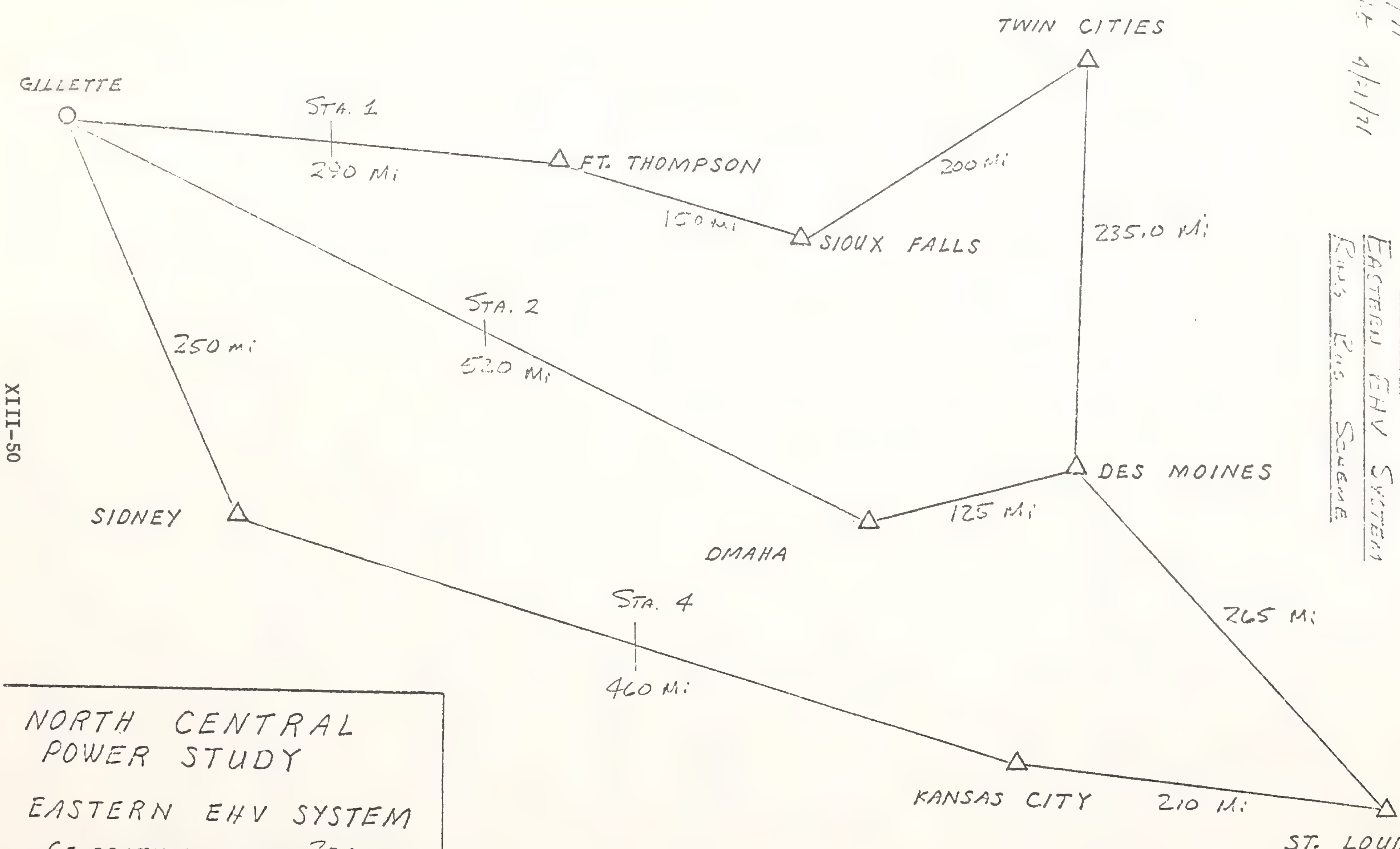
SIDNEY SUBSTATION



STOP 2 SWITCHING STATION

NOTE: 1) ALL REACTOR VALUES IN MVAR.
2) ALL CAPACITOR VALUES IN MVAR

EASTERN EHV SYSTEM
RING BUS SCHEME



NORTH CENTRAL
POWER STUDY

EASTERN EHV SYSTEM

GENERATION LEVEL = 3000 MW

VOLTAGE LEVEL = 500 KV

PLAN: E

CASE: 03E5-B03

Run Date ________ By ____

Recorded Date ________ By ____

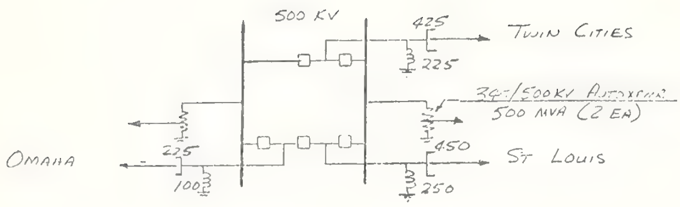
SAF 4/9/71
JJO 4/21/71

NCPS
EASTERN EHV SYSTEM
CASE 03E5-B03

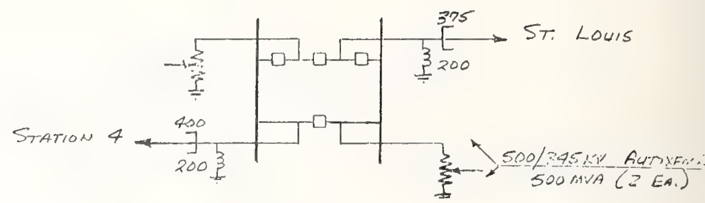
500 KV TRANSMISSION LINE DATA

TERMINAL 1		TERMINAL 2	MILAGE	CONDUCTOR NO. & SIZE
GILLETTE	-	STATION 1	145.0	2-2167 MCM ACSR
GILLETTE	-	STATION 2	260.0	
GILLETTE	-	SIDNEY	250.0	
STATION 1	-	FT. THOMPSON	145.0	
FT THOMPSON	-	SIOUX FALLS	150.0	
SIOUX FALLS	-	TWIN CITIES	200.0	
TWIN CITIES	-	DES MOINES	235.0	
DES MOINES	-	ST. LOUIS.	265.0	
STATION 2	-	OMAHA	260.0	
OMAHA	-	DES MOINES	125.0	
SIDNEY	-	STATION 4	230.0	
STATION 4	-	KANSAS CITY	230.0	
KANSAS CITY	-	ST. LOUIS	210.0	2-2167 MCM ACSR
		TOTAL MILAGE =	2705.0	

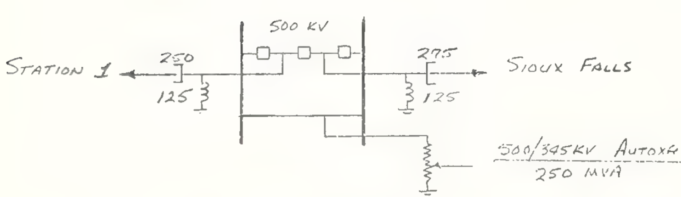
NCPS
Eastern EHV System
Case: 03E5 - B03



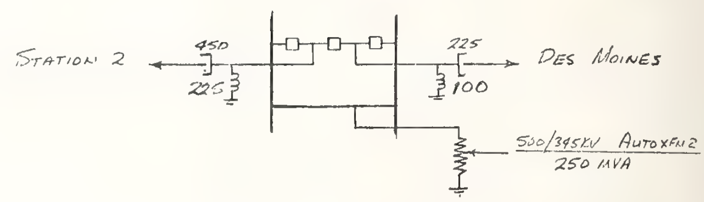
Des Moines Substation



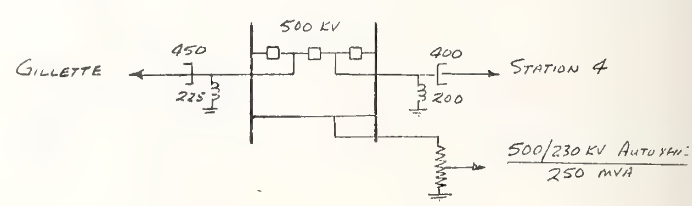
Kansas City Substation



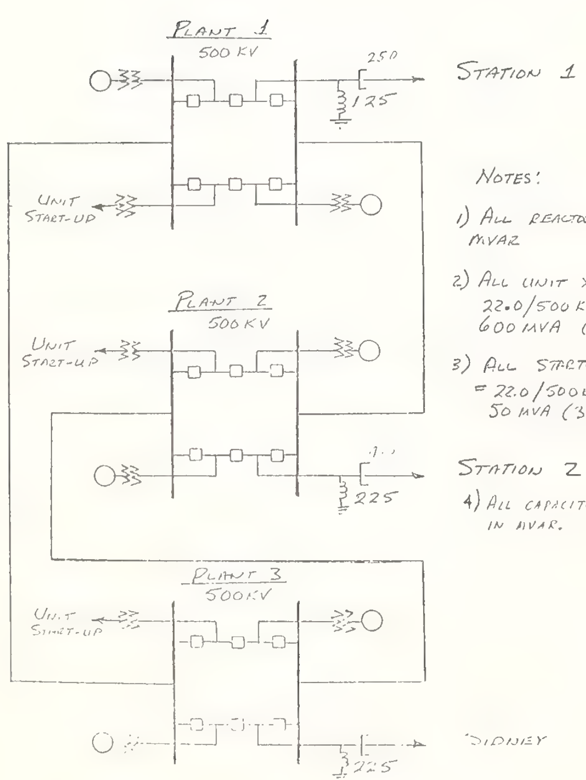
Ft Thompson Substation



Omaha Substation



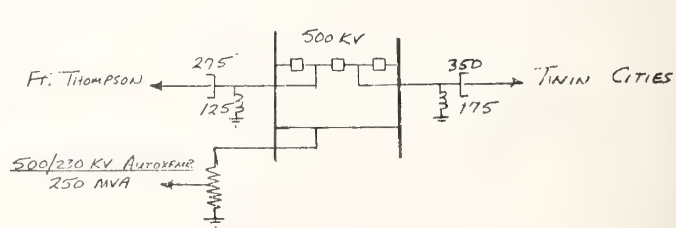
Sidney Substation



Notes:

1) All reactor values in MVAR
2) All unit xfmrs = 22.0/500 KV, 1Ø, 600 MVA (6 EA)
3) All start-up xfmrs = 22.0/500 KV, 1Ø, 50 MVA (3 EA.)
4) All capacitor values in MVAR.

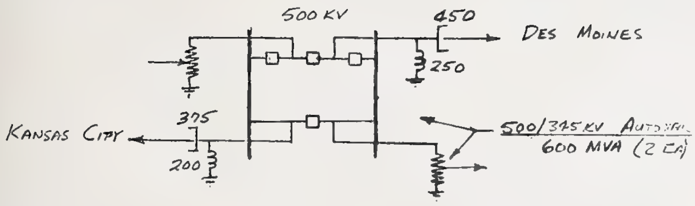
Gillette Complex



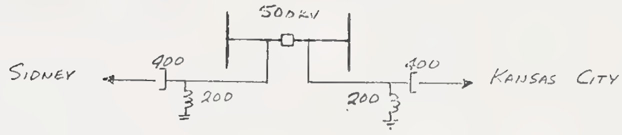
Sioux Falls Substation

Note: 1) All reactor & capacitor values in MVAR.

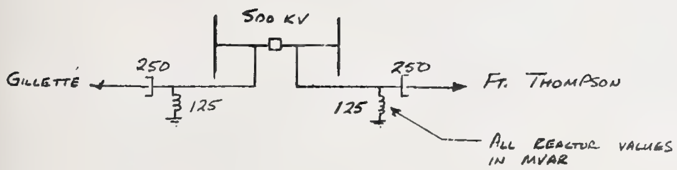
NCPS
EASTERN EHV SYSTEM
CASE: 03E5-B03



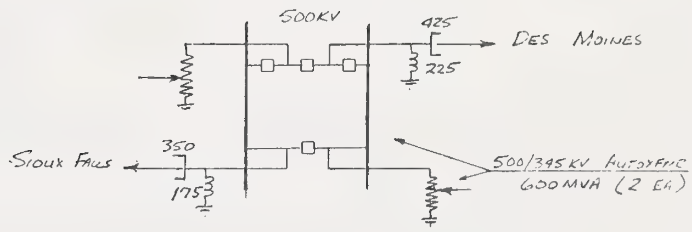
ST. LOUIS SUBSTATION



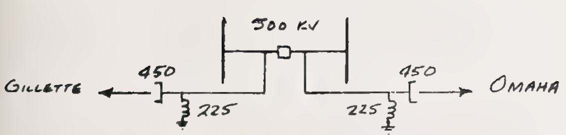
STATION 4 - SWITCHING STATION



STATION 1 - SWITCHING STATION



TWIN CITIES SUBSTATION



STATION 2 - SWITCHING STATION

NOTE: 1) ALL REACTOR & CAPACITOR VALUES IN MVAR.

V. Environmental Considerations

There is no set pattern for the location, design, and construction of transmission structures to make them acceptable to the public from an aesthetics standpoint. One area may accept a design which is entirely unacceptable to an area in a different part of the country. However, the following items merit consideration:

1. Hold public hearings to inform the public regarding the following:

   a. Projected future power needs of the people

   b. Alternate plans being considered to furnish the electric power needed by the people

   c. The cost of alternate designs and net effect on cost of power to the consumer

   d. The differences in consumption of nonreplenishable natural resources for alternate plans

2. Select routes that avoid sensitive areas and minimize the impact on the environment

3. Use earthy color tones for finishes on facilities to be treated or painted

4. Specify a dull finish for all galvanized steel structures

5. Make an effort to improve appearance of latticed structures by streamlining silhouette and reducing number of secondary structural members

6. Avoid heavily timbered areas, shelter belts, scenic areas, parks, monuments, recreation and historic areas, conflicts with present and planned uses of land, crossings at high points, and long views of lines

7. Preserve the natural landscape as much as practicable, minimize clearning of trees and brush, clearing along edges of right-of-way should be scalloped to avoid wide swath appearance, minimize construction of access roads which scar the landscape.

8. Lines should be screened from public view as much as possible. Locating lines part way up slopes to provide a background of topography can be very effective in reducing visual impact. Natural vegetation and terrain should be utilized to screen facilities from public view.

NORTH CENTRAL POWER STUDY

XIV. Technical Studies Task Force
Technical Report

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II. Results

III. Study Assumptions and Qualifications

IV. Study Procedures and Discussion

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- B. West System
- C. Beulah Generation Complex
- D. Determination of Reserve Requirement

V. Appendix - Calculations and Tables

- A. Transmission Load Factor Calculations
- B. Load Area Reserve Requirement
- C. System Generation and Losses

VI. Appendix - System Power Flow Diagrams

- A. 3,000 mw Eastern System - 765 kv
- B. 10,000 mw Eastern System - 765 kv
- C. 20,000 mw Eastern System - 765 kv
- D. 40,000 mw Eastern System - 765 kv
- E. 43,000 mw Eastern System - 765 kv
- F. 1,000 mw Western System - 500 kv
- G. 3,000 mw Western System - 500 kv
- H. 10,000 mw Western System - 500 kv
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- J. 3,000 mw Eastern System - 500 kv - Gillette Plan
- K. 1980 Detailed System and 3,000 mw EHV System Overlay

I. Introduction

The Technical Studies Task Force was assigned the task of determining transmission systems to deliver the power from mine-mouth generating plants to load centers. In addition, the Task Force was also to determine the transmission losses associated with the developed systems and the reserve requirements.

Working within the framework of study assumptions and qualifications as outlined in Section 3, transmission systems and reserve requirements were developed for several levels of generation.

II. Results

A. It would be technically feasible to deliver the bulk of the generated power to major load centers located in the Twin Cities, Omaha, Des Moines, Kansas City, and St. Louis areas.

B. For a generation level of 43,000 mw, a system of fourteen 765-kv lines arranged in four corridors would be adequate to deliver generated power under the study criteria and assumptions to the major load centers on the East System. System configuration and loading for the 43,000-mw delivery are shown on Diagram 1E in Section VI.

C. East System development at the other selected load levels of 3,000 mw, 10,000 mw, 20,000 mw, and 40,000 mw are shown on Diagrams 1A, 1B, 1C, and 1D, respectively.

D. The EHV system will have little effect on the underlying system and the underlying system will have little effect on the EHV system as shown on Diagrams 1K and 2K.

E. On the West System the 1,000-mw generation level will require two 500-kv lines; the 3,000-mw level, three 500-kv lines; and the 10,000-mw level, six 500-kv lines to the single Medicine Bow delivery point.

F. Comparison of the Gillette and Beulah generation sites at a 3,000-mw level of development shows the Gillette site required the equivalent of 235 more miles of 500-kv line.

G. The reserve requirement and transmission load factors are shown in the following table:

Development level	No. of units reserve	Transmission load factor %
3,000 mw east 1,000 mw west	0	85
10,000 mw east 3,000 mw west	1-1,000 mw	91
20,000 mw east 3,000 mw west	2-1,000 mw	92
40,000 mw east 10,000 mw west	1- 500 mw 4-1,000 mw	92

H. A 230-kv line from a point on the WBR Yellowtail-Custer transmission line near Hardin, Montana, to a proposed Wyodak, Wyoming, 230-kv switchyard would be adequate to supply loop power service to the pumping plants for supplying water to the generating powerplants.

III. Study Assumptions and Qualifications

This work was based on the following assumptions and qualifications that were established before the study was initiated or introduced as the work progressed:

A. The east-west ties were open, necessitating two study areas, an East System area and a West System area.

B. Voltage levels of the transmission system would be limited to existing technology and available equipment, presently 765 kv.

C. Power would be delivered from mine-mouth plants to load center delivery points, at levels of about 30 percent of area load growth. Minimum generation considered feasible for the study was 3,000 mw on the East System and 1,000 mw on the West System.

D. The phase angle between the generation area voltage and the load center voltage would be within 30° for normal system conditions and 42° for outages. These criteria were considered substitutes for stability studies.

E. Series capacitor compensation up to 80 percent for 500-kv lines and for 765-kv lines.

F. The East System would meet MARCA reliability requirements, and the West System would meet WSCC reliability requirements.

G. The reserve requirement for a transmission line outage would be supplied by the receiving system.

H. The reserve requirement for generator maintenance would be supplied at the generation area.

I. D-c transmission, although not ruled out in later phases, was not given consideration because of impracticalities of a multi-delivery point d-c system with presently available equipment.

J. The forced outage rate for determining reserve requirements used engineering judgment based on existing studies for smaller generating units than those units considered in this study.

IV. Study Procedures and Discussion

In order to determine the location of load centers, the rate of load growth, the generation levels to be studied, and the subsequent transmission required to deliver the generated power, the load data for the 1980-2000 period as compiled by the Load Projection Committee was analyzed by areas.

Based on supplying approximately 30 percent of the projected load growth, a total of eight levels of generation were selected to be studied. East System levels of 3,000 mw, 10,000 mw, 20,000 mw, 40,000 mw, and 40,000 mw plus 3,000 mw of hydropeaking were selected. West System levels of 1,000 mw, 3,000 mw, and 10,000 mw were selected for study.

East System load centers and factors developed for quantity of delivered power at each point of delivery were as follows:

	Percent of load
Oahe area	3.2
Sioux Falls	3.2
Twin Cities	22.7
Des Moines	16.8
Eastern Nebraska (Omaha)	5.1
Western Nebraska (Gering)	3.6
Kansas City	20.1
St. Louis	25.3
	100.0

On the West System, the only delivery point besides the generator buses was Medicine Bow, Wyoming.

A. East System

Using the above generation levels and delivery points, an EHV transmission plan was developed for each generation level for the East System.

The development used a simplified network representation that included only the 500-kv or 765-kv lines. A single generation source in the mine-mouth area was assumed. The lines were fully compensated with shunt reactors for line charging. The generation levels were held constant at 105 percent voltage. The system losses and reactive requirement were supplied at the farthest load delivery buses. Various system configurations were tested to arrive at a base system that would meet the system criteria for phase angle and line loadings. This was done for each of the generation levels.

The developed base plans were then checked for line outage performance. Power flow diagrams of the base and outage cases for each generation level are included in the Appendix, Section VI.A., B., C., D., and E.

In the initial phase of the study, 500-kv transmission was considered for the 3,000-mw level of development, with a combination 500-kv - 765-kv transmission system above this level. However, the economics of starting the development with 765 kv appears favorable on the basis of known factors. The impact of the multiplicity of transmission lines upon the environment, which would ultimately be required for even a 10,000-mw complex, appears to call for maximizing the capacity of each line. Likewise, to also maximize line capacity, the 765-kv lines were compensated at 80 percent. Indications are that there are no technical reasons not to compensate to this level.

To determine (a) the effect of the EHV on the underlying system and (b) the effect of the underlying system on phase angles of the EHV system, a task force developed the projected 1980 Eastern System from data supplied by study participants. This 1980 system was then overlaid with the 3,000-mw - 765-kv level of development. Power flow diagrams of the 1980 base case, the base case with the EHV overlay, and outage cases on the EHV system are included in the Appendix, Section VI.K. Since system development beyond 1980 is nebulous, testing the system at higher levels of generation was not considered practical.

Because of time limitations, the originally contemplated computer analysis of stability was dropped from the task force studies. In lieu of these studies, the system development was kept within criteria limits.

B. <u>West System</u>

Due to the single remote delivery point, a simple radial system was investigated from the generating complex to the Medicine Bow delivery point. Computer studies were run to check line loadings and power system angles for the three selected load levels. Power flow diagrams for these cases are included in the Appendix, Sections VI.F., G., and H.

C. <u>Beulah Generation Complex</u>

At the request of the Steering Committee, the feasibility of developing North Dakota lignite by comparing a 3,000-mw installation near Beulah, North Dakota, with a similar size installation near Gillette, Wyoming, was investigated. Because of the 3,000-mw generation level, only a 500-kv transmission system was considered. Using the same eight eastern load center delivery points as outlined previously, separate 500-kv systems were developed for the Beulah and Gillette generation sites. Similar plant switchyards and plant interconnection system were considered for each generation complex.

An equivalent of 235 more miles of 500-kv transmission lines would be needed from the Gillette site over the transmission needed for the Beulah site.

It is possible that a combination of the Beulah and Gillette areas would result in lower costs than development of either separately. Also a change in the load center delivery points would certainly have an effect on the comparisons. However, because of time limitation, these alternates were not studied. Power flow diagrams for each of the systems are included in the Appendix, Sections VI.I. and J.

D. Determination of Reserve Requirements

Using the forced outage rate of 5 percent for 500-mw units and 7 percent for 1,000-mw units as proposed by the Thermal Generation Task Force and the assumption that reserves for scheduled maintenance outage would be at the generator complex, the number of units required for normal maintenance reserve and the Normal Transmission Load Factor were determined. A Transmission Load Factor of 90 percent or better was desired except for the 3,000-mw level on the East and the 1,000-mw level on the West. For these levels it was assumed that the maintenance reserve requirement would be supplied at the load area.

The reserve requirements for transmission outages were determined for all generation levels. The limits used were a maximum power angle across the system of 42° and a maximum of 5,000-mw power flow on any line. These requirements (shown in Table B in the Appendix, Section V) were developed for the worst two-line outage case at each generation level. The reserve requirement was the amount that the generation had to be reduced at the source (so that the power angle did not exceed 42°). In some cases, in order to limit line flows to 5,000 mw, some switching of series capacitors was required to achieve uniform balance of loading.

V. Appendix - Calculations and Tables

A. Transmission Load Factor Calculations

1. Assumptions

a. Forced outage rates
   500 mw units 5%
   1000 mw units 7%

b. Maintenance requirements
   One month per year for each unit

2. 3000 MW East, 1000 MW West

a. East: 6-500 mw units
   C. F. (capacity factor) = 0.95 x 11/12
   = 0.871

b. West: 2-500 mw units
   C. F. = 0.871

c. Total transmission load factor (TLF)
   = 0.871

3. 10,000 MW East, 3000 MW West

a. East: 6-500 mw units
   7-1000 mw units
   1-1000 mw unit (spare)

Spare unit can be scheduled for 11 months annually. It would replace each of the 7 1000's in turn over 7 months and two each month of the 500's over 3 months. This leaves one month to provide maintenance capacity for the Western System.

For 7 Months	MW-Mos.
7000 x 0.93 x 7 =	45,570
3000 x 0.95 x 7 =	19,950
For 3 Months	
8000 x 0.93 x 3 =	22,320
2000 x 0.95 x 3 =	5,700
For 2 Months (no maint.)	
7000 x 0.93 x 2 =	13,020
3000 x 0.95 x 2 =	5,700
Total	112,260

TLF = 112,260/(10,000 x 12) = 0.936

b. West: 6-500 mw units

Use spare unit for 1 month to replace 2-500's during maintenance.

For 6 Units for 11 Months	MW-Mos.
3000 x 0.95 x 11 =	31,350
For Spare for 1 Month	
1000 x 0.93 x 1 =	930
Total	32,280

TLF = 32,280 (3,000 x 12) = 0.897

c. Total TLF = (112,260 + 32,280)/(13,000 x 12) = 0.927

4. 20,000 MW East, 3,000 MW West

a. East: 6-500 mw units
17-1000 mw units
2-1000 mw units (spare)

Each spare unit is available for 11 months. One can cover maintenance for 11 of the 17 1000's, the other can cover the remaining 6 1000's over a six month period, two 500's each month over a three month period and Western System Units for two months.

For 6 Months	MW-Mos.
17,000 x 0.93 x 6 =	94,860
3,000 x 0.95 x 6 =	17,100
For 3 Months	
18,000 x 0.93 x 3 =	50,220
2,000 x 0.95 x 3 =	5,700
For 3 Months (no maint.)	
17,000 x 0.93 x 3 =	47,430
3,000 x 0.95 x 3 =	8,550
Total	223,860

TLF = 223,860/(20,000 x 12) = 0.933

b. West: 6-500 mw units

Use one of spare 1000's for two months to replace two 500's each month.

For 6 Units for 11 Months	MW-Mos.
1000 x 0.95 x 11 =	31,350
For Spare for 2 Months	
1000 x 0.93 x 2 =	1,860
Total	33,210

TLF = 33,210/(3,000 x 12) = 0.922

c. Total TLF = (223,860 + 33,210)/(23,000 x 12) = 0.931

5. 40,000 MW East, 10,000 MW West

a. East: 6-500 mw units
37-1000 mw units
1-500 mw unit (spare)
4-1000 mw units (spare)

Assume each spare unit is available for 11 months per year. Three of the 4 1000 spares will cover 33 base 1000's. The remaining 1000 mw spare will cover the 4 remaining 1000 mw Eastern base units and all Western 1000's. The 500 mw spare will cover all six Eastern 500 mw units and five of the 6 Western 500's. For the Eastern System:

	MW-Mos.
37,000 x 0.93 x 12 =	412,920
3,000 x 0.95 x 12 =	34,200
Total	447,120

TLF = 447,120/(40,000 x 12) = 0.932

b. West: 7-1000 mw units
6-500 mw units

Spare units provide maintenance capacity for all units except 1-500 (see above).

For 7-1000 mw Units for 12 Months	MW-Mos.
7,000 x 0.93 x 12 =	78,120
For 5-500 mw Units for 12 Months	
2,500 x 0.95 x 12 =	28,500
For 1-500 mw Unit for 11 Months	
500 x 0.95 x 11 =	5,225
Total	111,845

TLF = 111,845/(10,000 x 12) = 0.932

c. Total TLF = (447,120 + 111,845) (50,000 x 12) = 0.932

B. Load Area Reserve Requirement

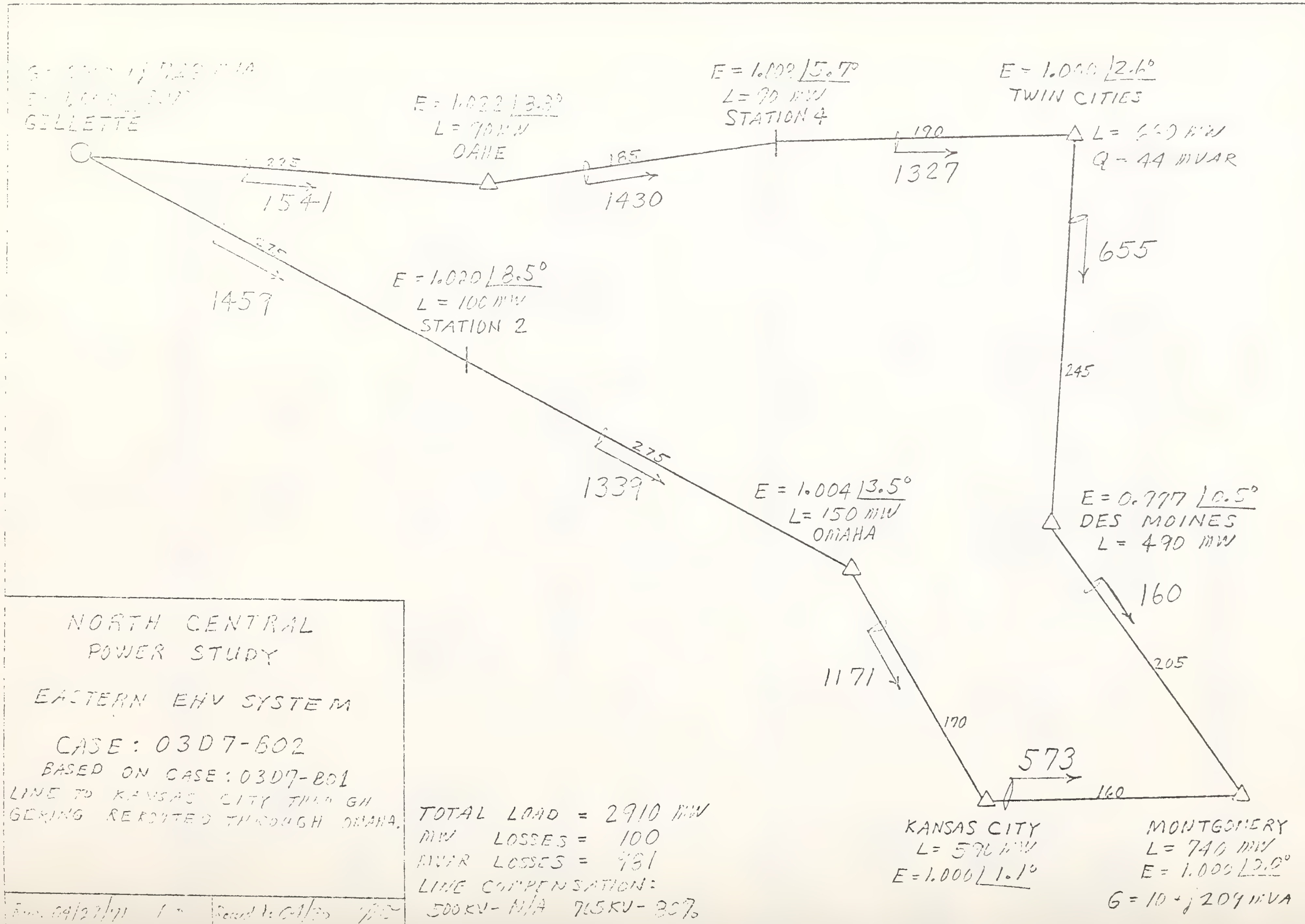
Development level	Total area load	Area reserve @ 15 percent of load	Reserve for loss of two lines	Additional load area reserve
EAST				
3,000	30,000	4,500	3,000	*
10,000	60,000	9,000	1,350	0
20,000	90,000	13,500	1,000	0
40,000	150,000	22,500	0	0
WEST				
1,000	1,000	1,500	800	**
3,000	20,000	3,000	0	0
10,000	40,000	6,000	0	0

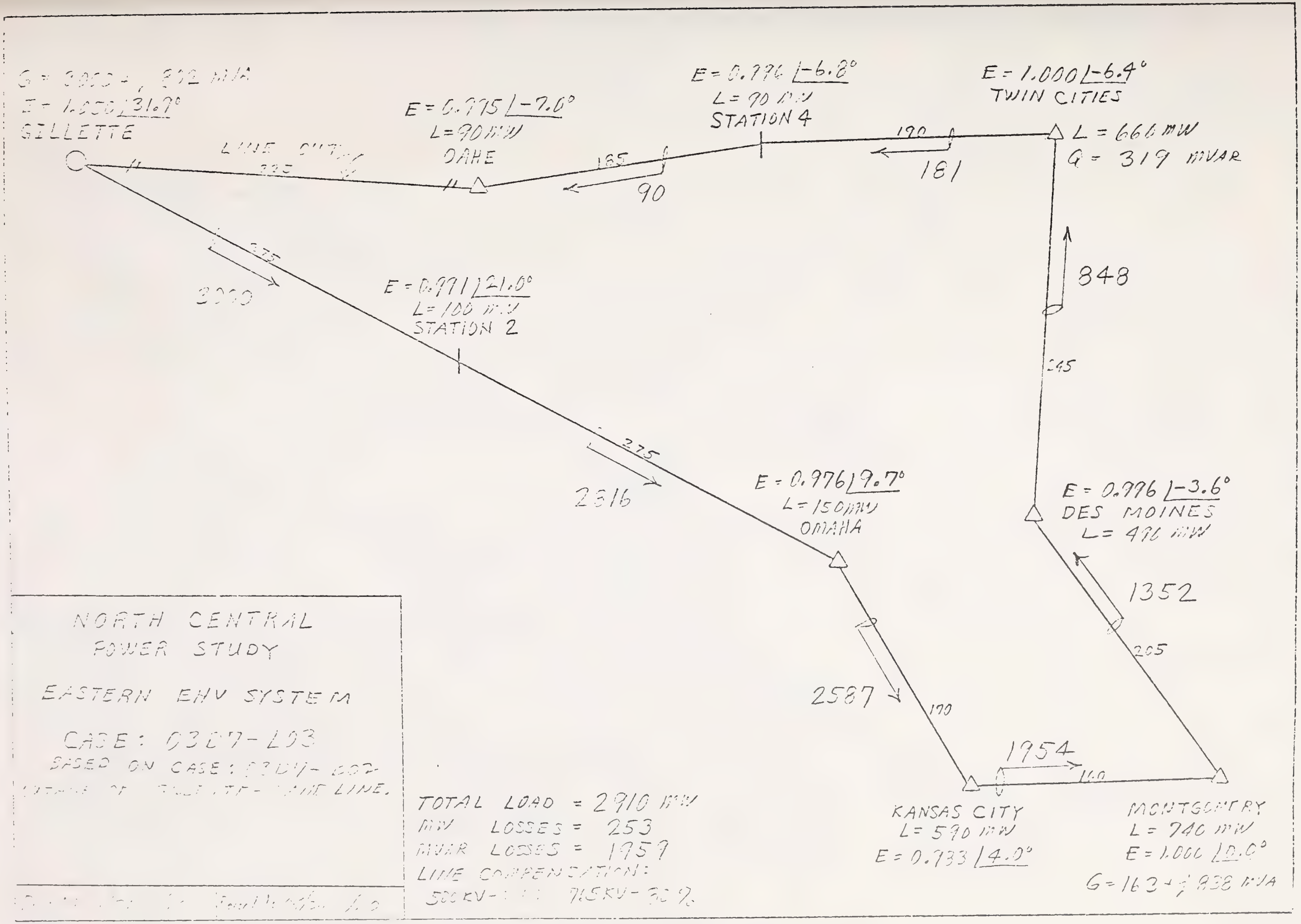
* Interconnections assumed to supply up to 1,500 mw for third contingency.
** Systems in Colorado and Utah can each withstand the loss of 400 mw.

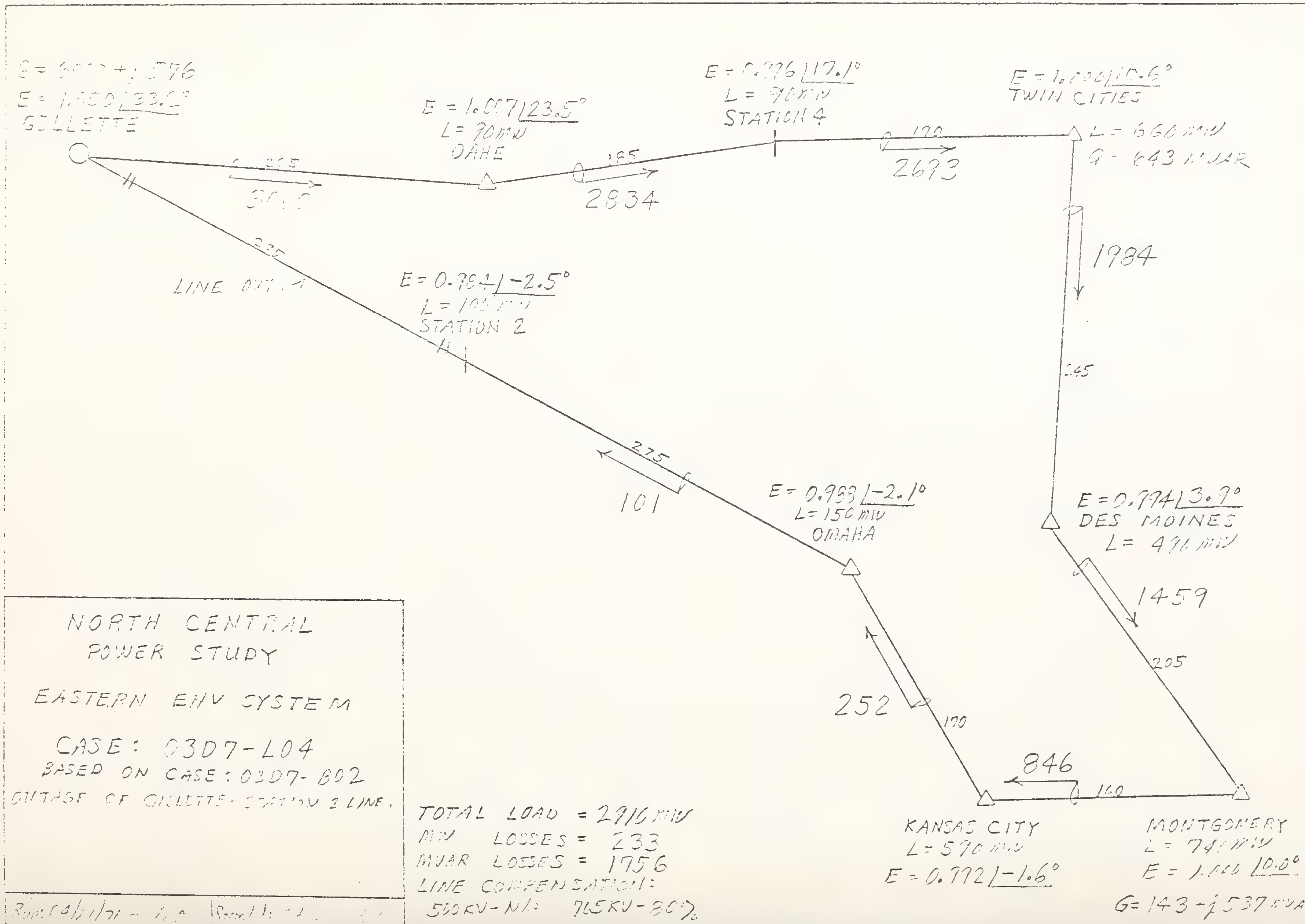
C. System Generation and Losses

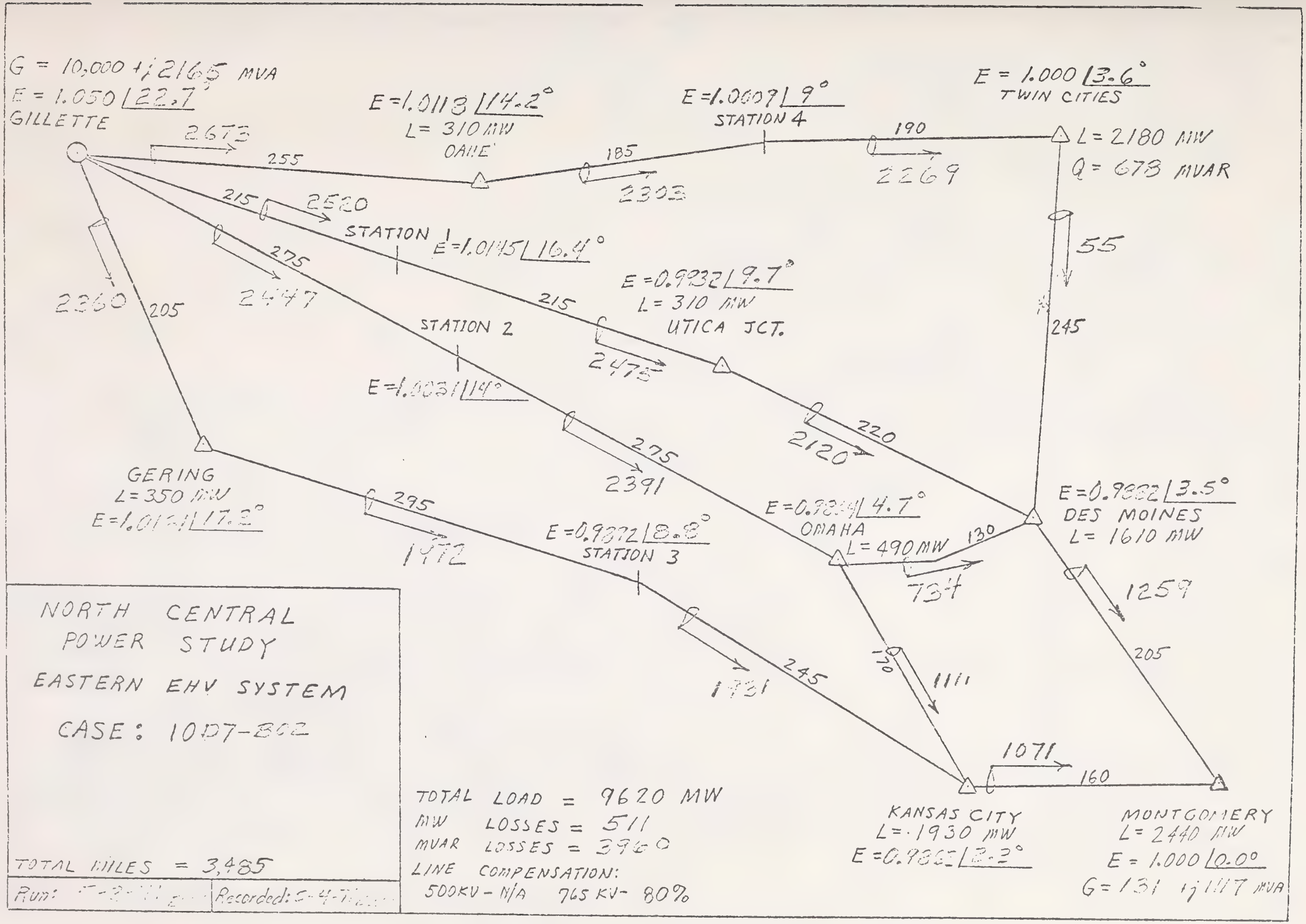
Generation capacity	Gen-energy mw - yrs/yr	System loss mw	System loss percent	System losses mw - yrs/yr
EAST				
3,000	2,550	100	3.30	76
10,000	9,100	511	5.11	435
20,000	18,400	1,266	6.33	1,100
40,000	36,800	2,704	6.76	2,360
* 43,000	37,500	2,864	6.66	2,500
WEST				
1,000	850	9	0.90	7
3,000	2,745	36	1.20	31
10,000	9,200	183	1.83	159

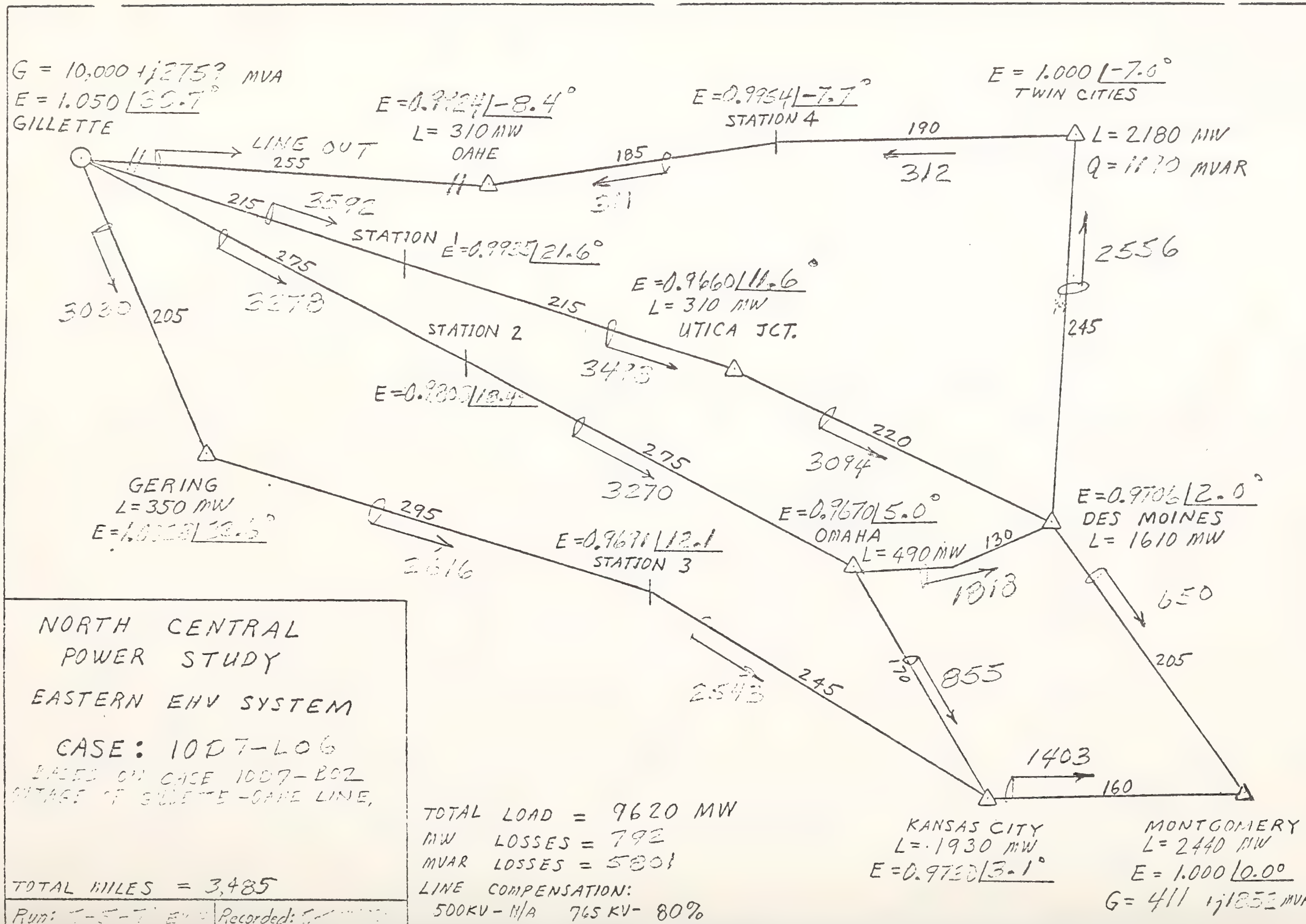
* Energy for pumping is assumed to come from load area generation during offpeak periods and would be about 1,000 mw - yrs/year.

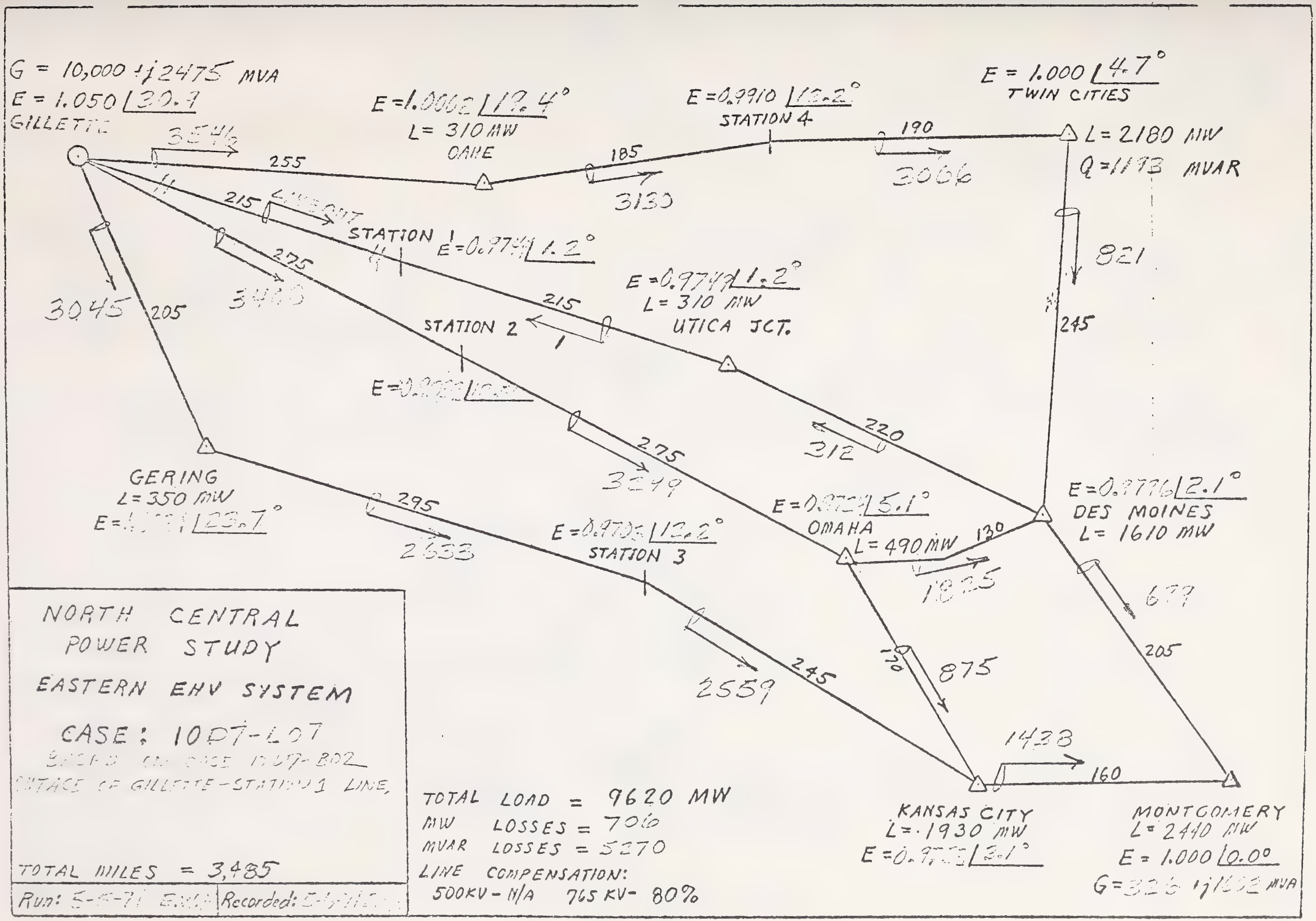

GILLETTE
E = 1.022 ∠3.3°
L = 70 MW
OAHE
E = 1.009 ∠5.7°
L = 90 MW
STATION 4
E = 1.000 ∠2.6°
TWIN CITIES
L = 640 MW
Q = 44 MVAR
225
1541
185
1430
190
1327
655
245
275
1457
E = 1.020 ∠8.5°
L = 100 MW
STATION 2
275
1339
E = 1.004 ∠3.5°
L = 150 MW
OMAHA
E = 0.977 ∠0.5°
DES MOINES
L = 490 MW
160
205
1171
170
573
160
KANSAS CITY
L = 590 MW
E = 1.000 ∠1.1°
MONTGOMERY
L = 740 MW
E = 1.000 ∠2.0°
G = 10 + j 209 MVA
TOTAL LOAD = 2910 MW
MW LOSSES = 100
MVAR LOSSES = 961
LINE COMPENSATION:
500KV - N/A 765KV - 30%
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 03D7-B02
BASED ON CASE: 03D7-B01
LINE TO KANSAS CITY THRU GN
GENING REROUTED THROUGH OMAHA.

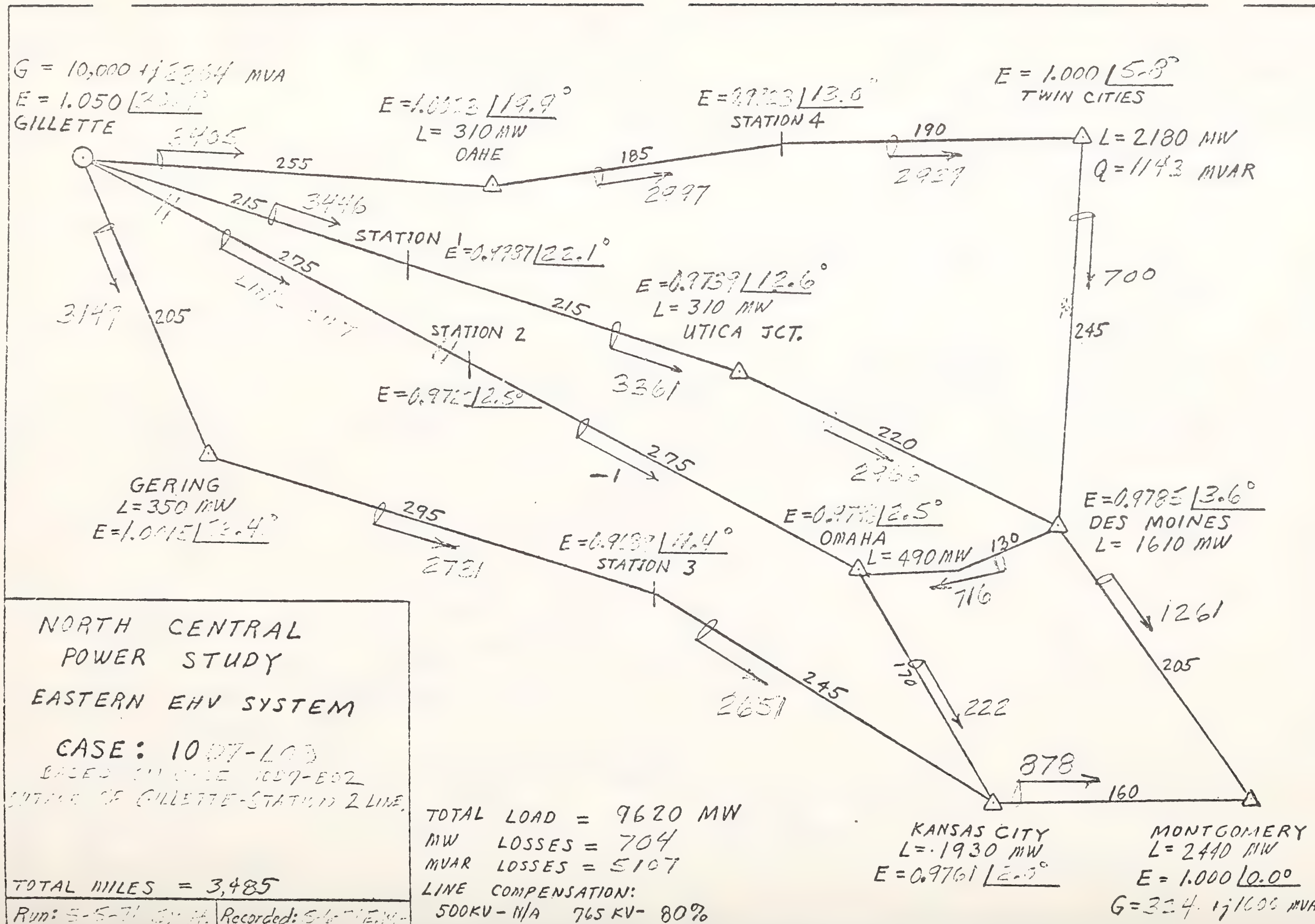

GILLETTE
E = 0.995 /-7.0°
L = 90 MW
OAHE
E = 0.996 /-6.8°
STATION 4
E = 1.000 /-6.4°
TWIN CITIES
L = 666 MW
Q = 319 MVAR
90
181
848
E = 0.991 /21.0°
L = 100 MW
STATION 2
2316
E = 0.976 /9.7°
L = 150 MW
OMAHA
E = 0.996 /-3.6°
DES MOINES
1352
2587
1954
KANSAS CITY
L = 590 MW
E = 0.933 /4.0°
L = 740 MW
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
TOTAL LOAD = 2910 MW
MW LOSSES = 253
MVAR LOSSES = 1959

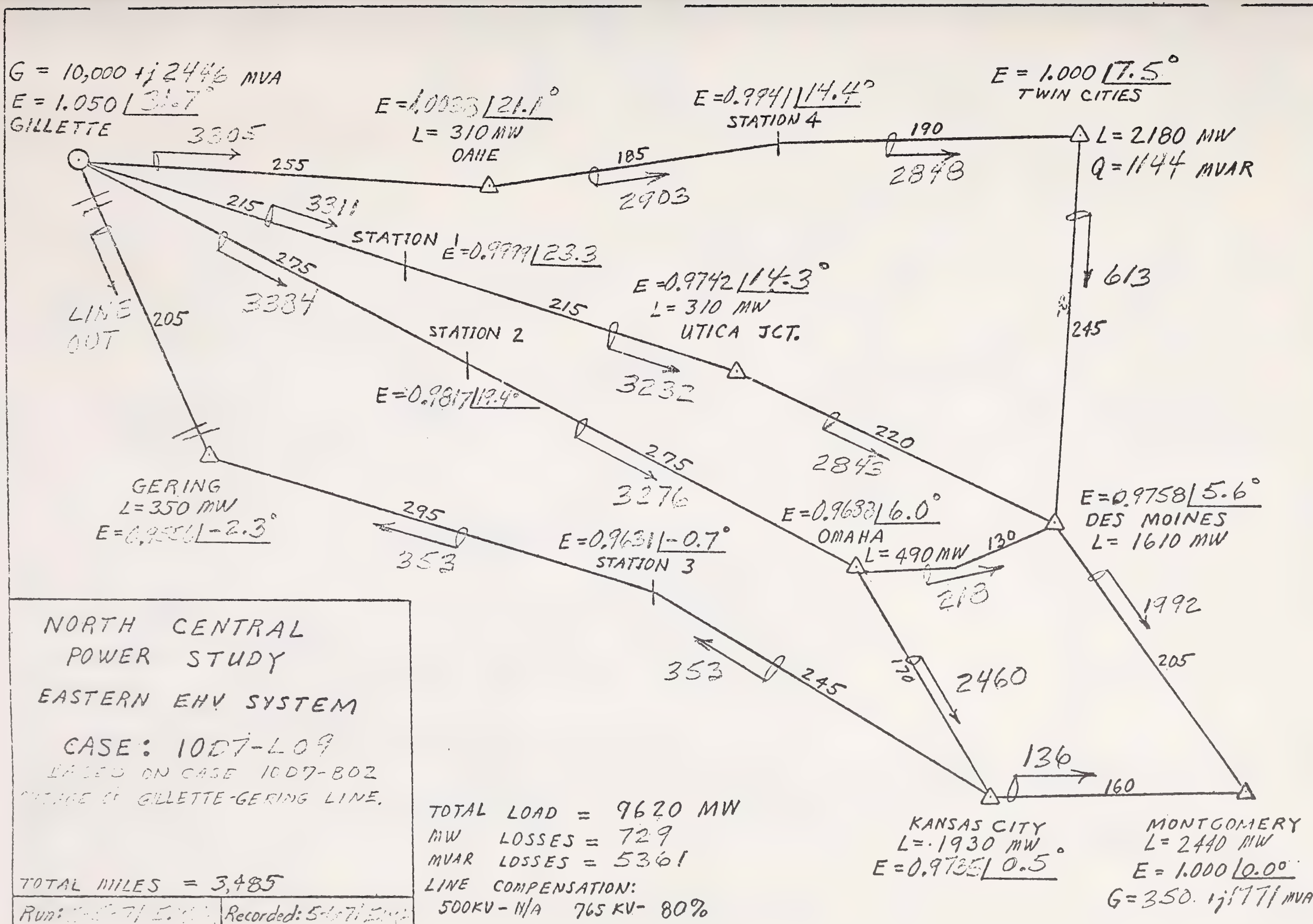

E = 1.050 |33.0°
GILLETTE
E = 1.007 |23.5°
L = 70 MW
OAHE
E = 0.996 |17.1°
L = 70 MW
STATION 4
TWIN CITIES
L = 660 MW
Q = 643 MVAR
1984
245
2834
2693
185
170
LINE OUT
E = 0.984 |-2.5°
STATION 2
275
101
E = 0.988 |-2.1°
L = 150 MW
OMAHA
E = 0.994 |3.9°
DES MOINES
L = 491 MW
1459
205
252
170
846
160
KANSAS CITY
L = 590 MW
E = 0.992 |-1.6°
MONTGOMERY
L = 741 MW
G = 143 - j 537 MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 03D7-L04
BASED ON CASE: 03D7-B02
OUTAGE OF GILLETTE-STATION 2 LINE.
TOTAL LOAD = 2916 MW
MW LOSSES = 233
MVAR LOSSES = 1756
LINE COMPENSATION:
500KV-N/A 765KV-80%


G = 10,000 +j2165 MVA
E = 1.050 ∠22.7
GILLETTE
2673
255
E = 1.0113 ∠14.2°
L = 310 MW
OAHE
185
2303
E = 1.0007 ∠9°
STATION 4
190
2269
E = 1.000 ∠3.6°
TWIN CITIES
L = 2180 MW
Q = 678 MVAR
55
245
215
2520
STATION 1
E = 1.0145 ∠16.4°
275
2447
2360
205
STATION 2
E = 1.0031 ∠14°
215
E = 0.9932 ∠9.7°
L = 310 MW
UTICA JCT.
2475
220
2120
275
2391
GERING
L = 350 MW
E = 1.0141 ∠17.2°
295
1472
E = 0.9872 ∠8.8°
STATION 3
E = 0.9844 ∠4.7°
OMAHA
L = 490 MW
130
734
E = 0.9882 ∠3.5°
DES MOINES
L = 1610 MW
1259
205
245
1731
170
1111
1071
160
KANSAS CITY
L = 1930 MW
E = 0.9865 ∠2.2°
MONTGOMERY
L = 2440 MW
E = 1.000 ∠0.0°
G = 131 +j1117 MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 10D7-B02
TOTAL LOAD = 9620 MW
MW LOSSES = 511
MVAR LOSSES = 3960
LINE COMPENSATION:
500KV - N/A 765 KV - 80%
TOTAL MILES = 3,485
Run:
Recorded:

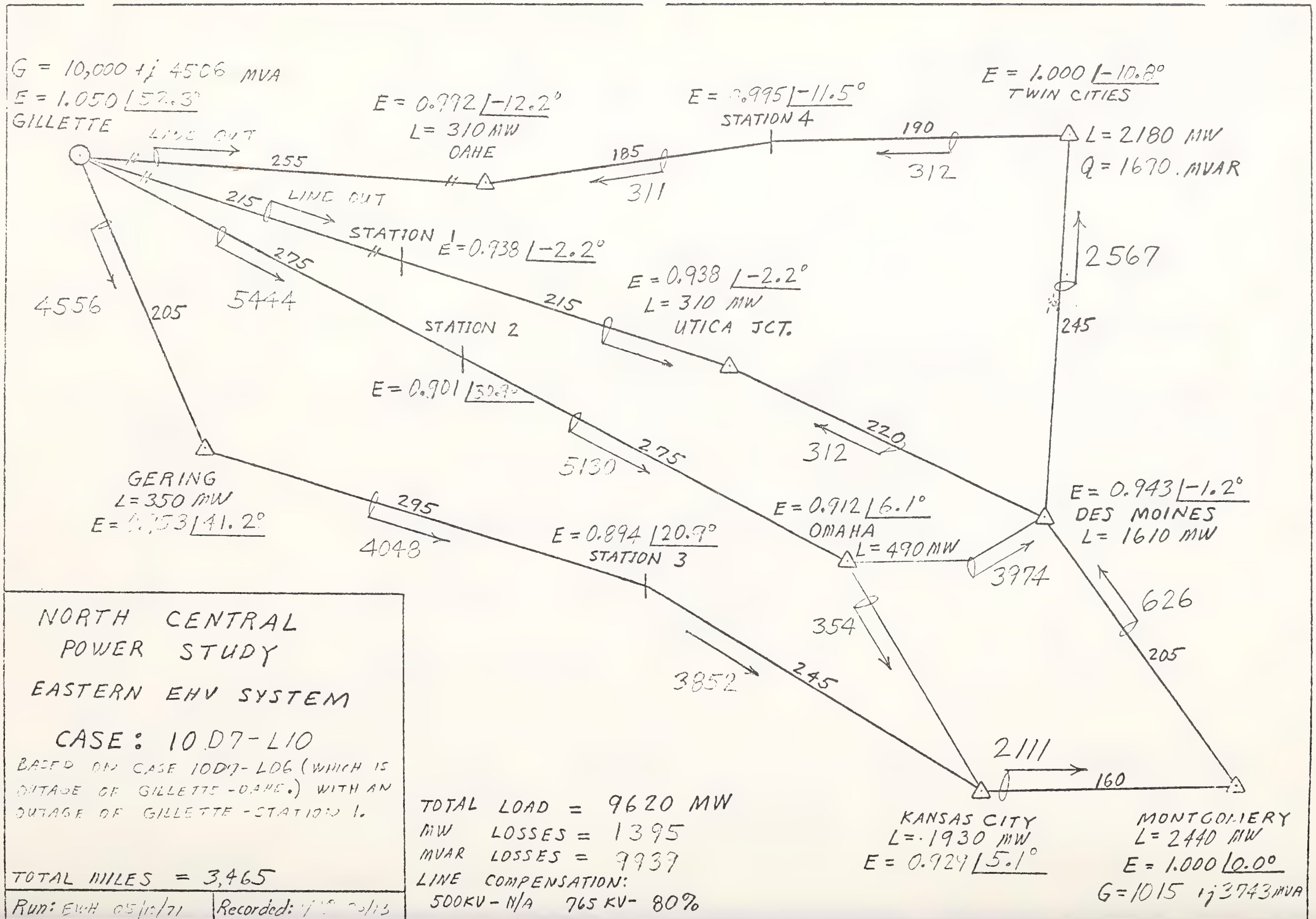

G = 10,000 + j2759 MVA
E = 1.050 /30.7°
GILLETTE
LINE OUT
255
E = 0.9924 /-8.4°
L = 310 MW
OAHE
E = 0.9954 /-7.7°
STATION 4
E = 1.000 /-7.0°
TWIN CITIES
L = 2180 MW
Q = 1170 MVAR
190
312
185
215
3592
STATION 1
E = 0.9935 /21.6°
275
3378
3030
205
2556
245
215
E = 0.9660 /11.6°
L = 310 MW
UTICA JCT.
STATION 2
3478
E = 0.9800 /18.4°
220
3094
275
3270
E = 0.9706 /2.0°
DES MOINES
L = 1610 MW
GERING
L = 350 MW
295
3616
E = 0.9671 /12.1
STATION 3
E = 0.9670 /5.0°
OMAHA
L = 490 MW
130
1818
650
205
245
2548
170
855
1403
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 1007-L06
TOTAL LOAD = 9620 MW
MW LOSSES = 792
MVAR LOSSES = 5801
LINE COMPENSATION:
500KV - N/A 765 KV - 80%
KANSAS CITY
L = 1930 MW
E = 0.9730 /3.1°
MONTGOMERY
L = 2440 MW
E = 1.000 /0.0°
G = 411 + j1853 MVA
TOTAL MILES = 3,485
Run:
Recorded:

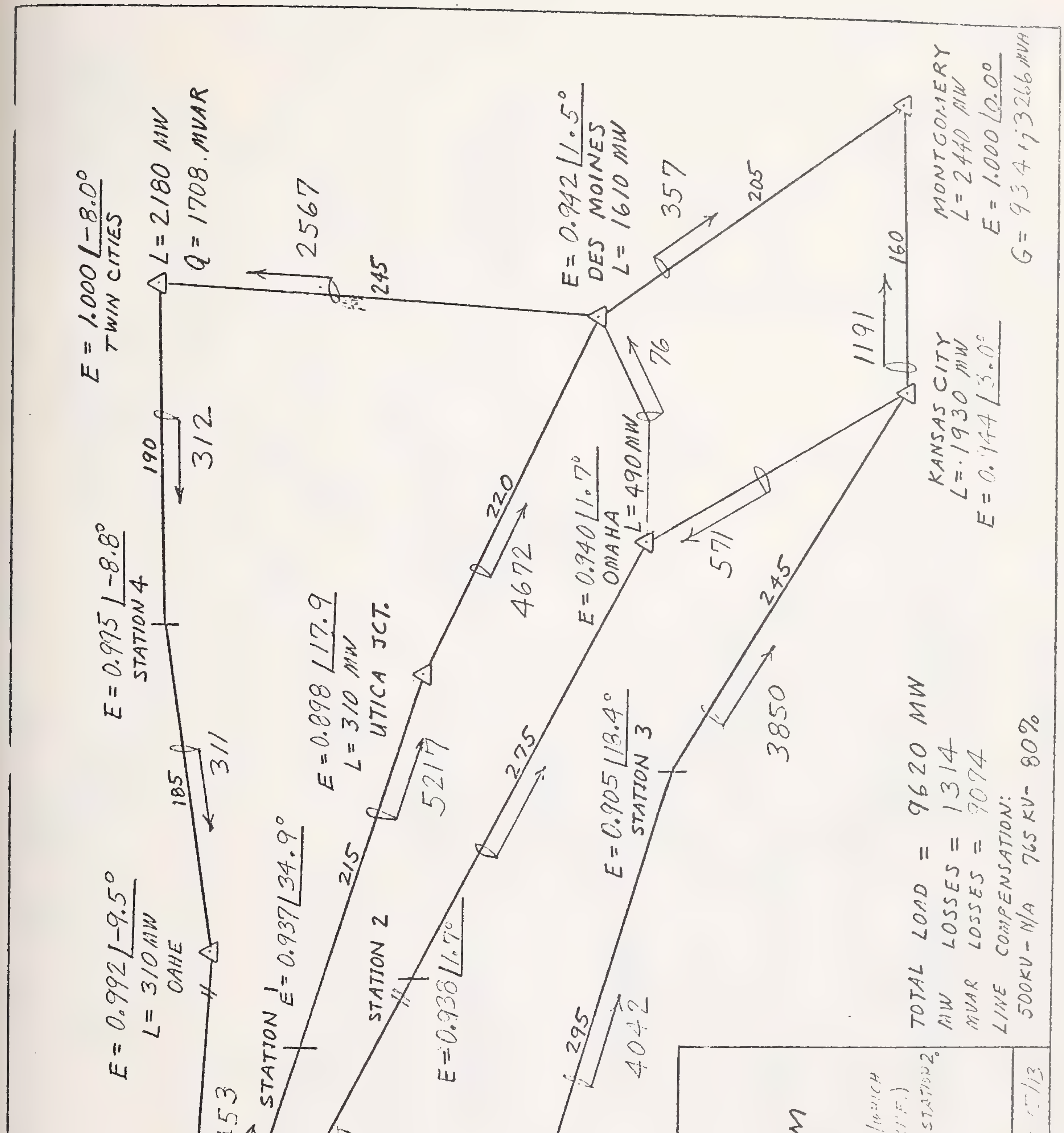

G = 10,000 +j2475 MVA
E = 1.050 ∠30.7
GILLETTE
E = 1.0002 ∠19.4°
L = 310 MW
OAHE
E = 0.9910 ∠13.2°
STATION 4
E = 1.000 ∠4.7°
TWIN CITIES
L = 2180 MW
Q = 1193 MVAR
255
185
190
3130
3066
821
245
215
275
205
3045
STATION 1
E = 0.9744 ∠1.2°
STATION 2
E = 0.9749 ∠1.2°
L = 310 MW
UTICA JCT.
215
220
312
275
3249
GERING
L = 350 MW
295
2633
E = 0.9703 ∠13.2°
STATION 3
E = 0.9776 ∠2.1°
DES MOINES
L = 1610 MW
OMAHA
L = 490 MW
130
1825
170
875
245
2559
205
1438
160
KANSAS CITY
L = 1930 MW
MONTGOMERY
L = 2440 MW
E = 1.000 ∠0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 10PT-LOT
TOTAL MILES = 3,485
Run:
Recorded:
TOTAL LOAD = 9620 MW
MW LOSSES = 706
MVAR LOSSES = 5270
LINE COMPENSATION:
500KV - N/A 765 KV - 80%


G = 10,000 MVA
E = 1.050
GILLETTE
255
215
3446
275
205
3149
E = 19.9°
L = 310 MW
OAHE
185
2997
E = 13.6°
STATION 4
190
E = 1.000 5.8°
TWIN CITIES
L = 2180 MW
Q = 1143 MVAR
700
245
STATION 1
E = 0.9937 22.1°
215
E = 0.9739 12.6°
L = 310 MW
UTICA JCT.
3361
220
STATION 2
E = 0.972 2.5°
275
-1
E = 0.9785 3.6°
DES MOINES
L = 1610 MW
1261
205
E = 2.5°
OMAHA
L = 490 MW
13°
716
170
222
GERING
L = 350 MW
295
2731
STATION 3
245
2651
878
160
KANSAS CITY
L = 1930 MW
E = 0.9761
MONTGOMERY
L = 2440 MW
E = 1.000 0.0°
MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 10
GILLETTE-STATION 2 LINE
TOTAL MILES = 3,485
Run:
Recorded:
TOTAL LOAD = 9620 MW
MW LOSSES = 704
MVAR LOSSES = 5107
LINE COMPENSATION:
500KV - N/A 765 KV - 80%

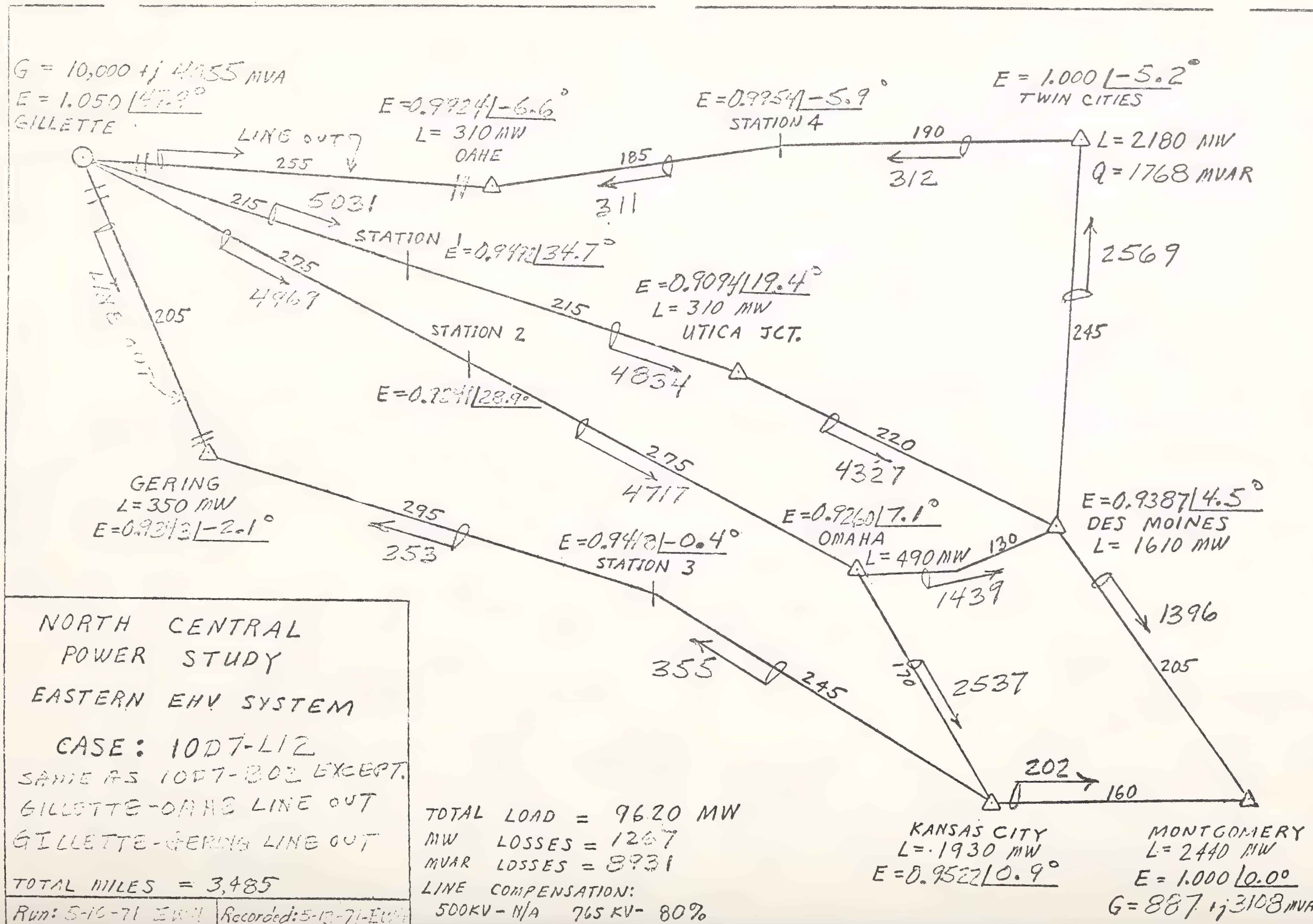


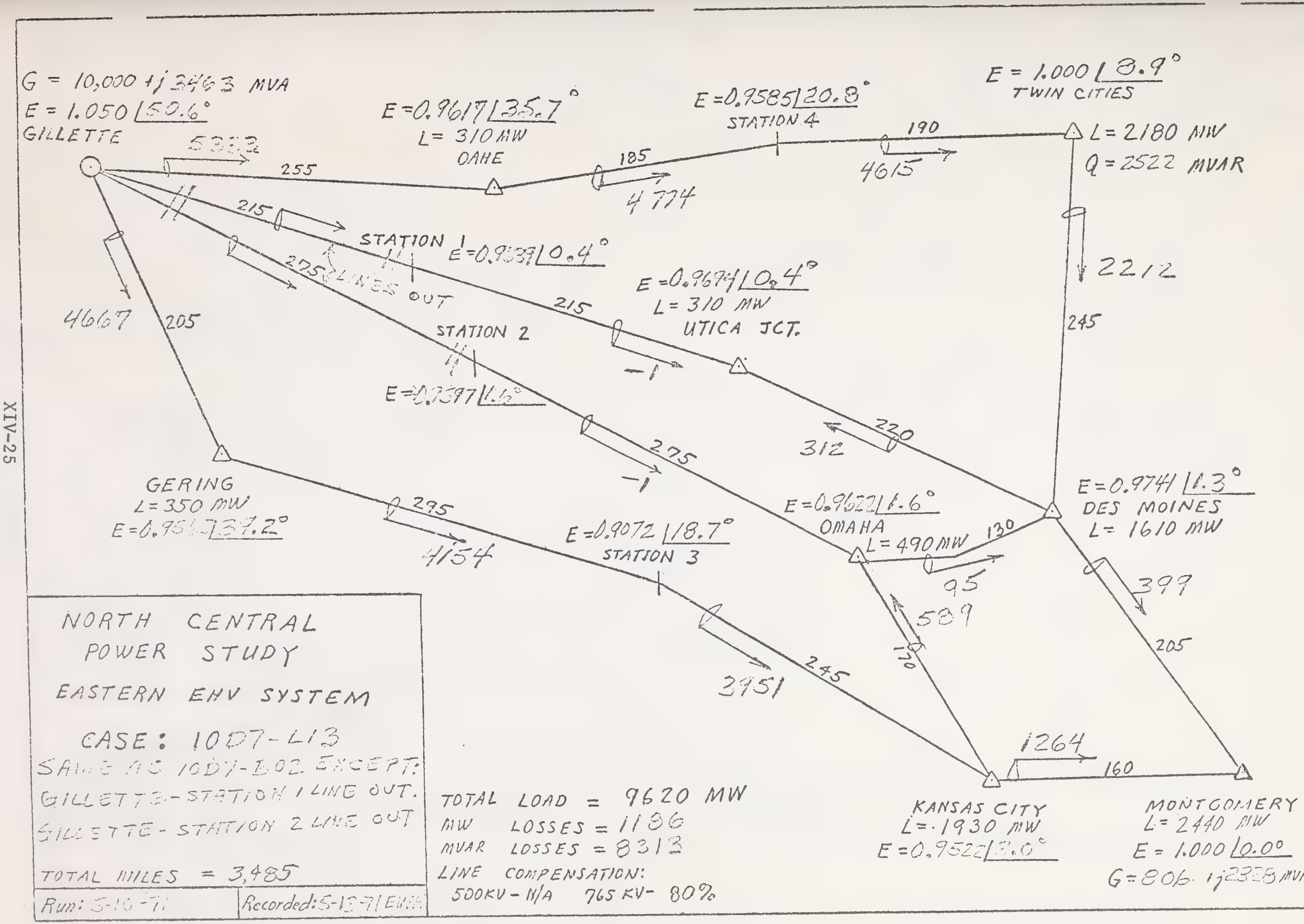
G = 10,000 +j 2446 MVA
E = 1.050
GILLETTE
3305
255
E = 21.1°
L = 310 MW
OAHE
185
2903
E = 0.9941 14.4°
STATION 4
190
2848
E = 1.000 17.5°
TWIN CITIES
L = 2180 MW
Q = 1144 MVAR
215
3311
STATION 1
E = 0.9999 23.3
275
3384
LINE OUT
205
STATION 2
E = 0.9817 19.4°
215
3232
E = 0.9742 14.3°
L = 310 MW
UTICA JCT.
613
245
220
2843
275
3276
E = 0.9758 5.6°
DES MOINES
L = 1610 MW
GERING
L = 350 MW
-2.3°
295
353
E = 0.9631 -0.7°
STATION 3
E = 0.9683 6.0°
OMAHA
L = 490 MW
130
218
1992
353
245
170
2460
205
136
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 1007-L09
GILLETTE-GERING LINE.
TOTAL MILES = 3,485
Run:
Recorded:
TOTAL LOAD = 9620 MW
MW LOSSES = 729
MVAR LOSSES = 5361
LINE COMPENSATION:
500KV - N/A 765 KV - 80%
KANSAS CITY
L = 1930 MW
0.5°
MONTGOMERY
L = 2440 MW
E = 1.000 0.0°
G = 350 +j 1771 MVA

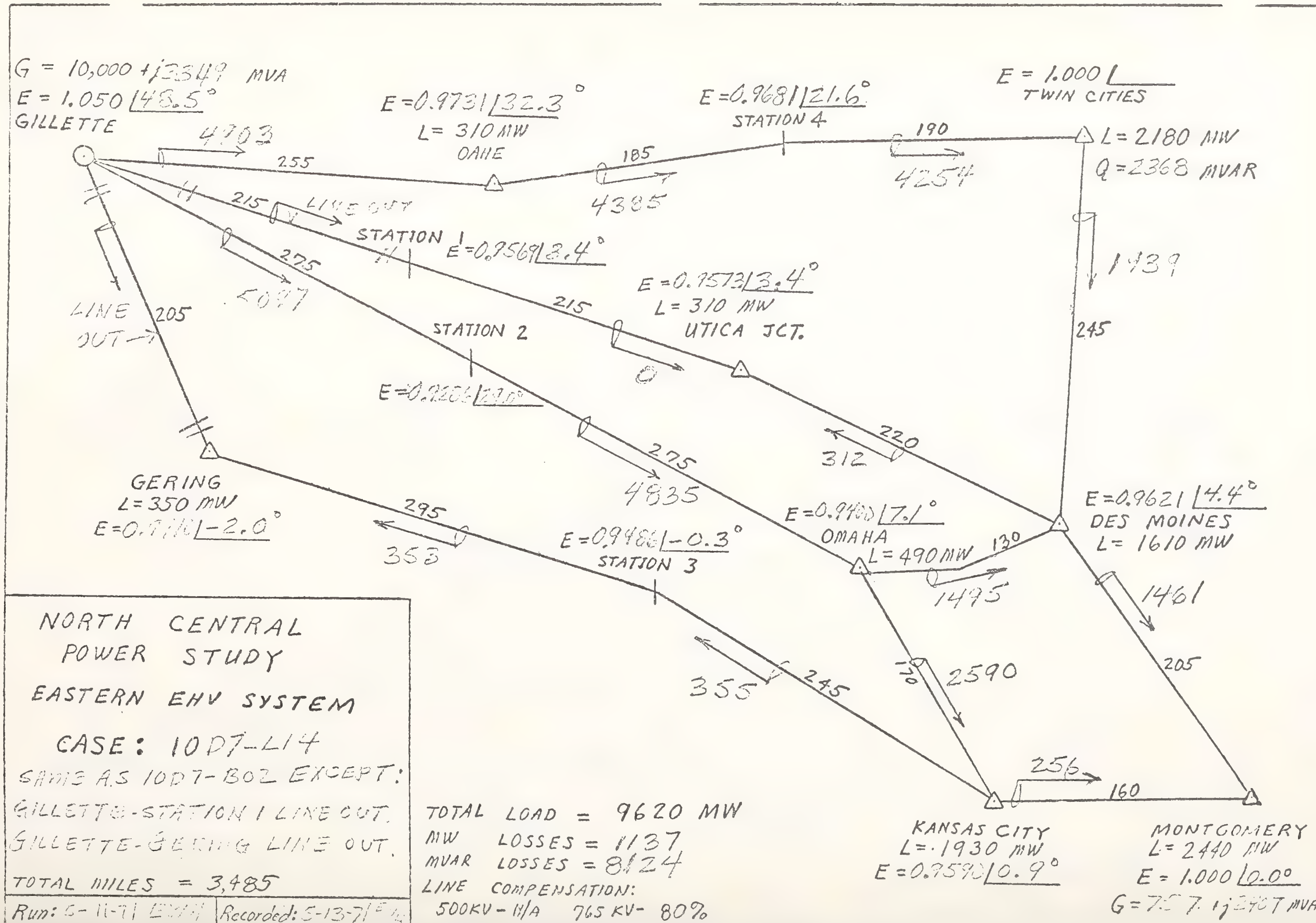

G = 10,000 +j 4506 MVA
E = 1.050 /52.3°
GILLETTE
LINE OUT
255
E = 0.992 /-12.2°
L = 310 MW
OAHE
185
311
E = 0.995 /-11.5°
STATION 4
190
312
E = 1.000 /-10.8°
TWIN CITIES
L = 2180 MW
Q = 1670. MVAR
215
LINE OUT
STATION 1
E = 0.938 /-2.2°
275
5444
4556
205
215
E = 0.938 /-2.2°
L = 310 MW
UTICA JCT.
2567
245
STATION 2
E = 0.901
275
5130
220
312
GERING
L = 350 MW
41.2°
295
4048
E = 0.894 /20.9°
STATION 3
E = 0.912 /6.1°
OMAHA
L = 490 MW
3974
E = 0.943 /-1.2°
DES MOINES
L = 1610 MW
626
205
354
3852
245
2111
160
KANSAS CITY
L = 1930 MW
E = 0.924 /5.1°
MONTGOMERY
L = 2440 MW
E = 1.000 /0.0°
G = 1015 +j3743 MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 10D7-L10
BASED ON CASE 10D7-L06 (WHICH IS OUTAGE OF GILLETTE-OAHE.) WITH AN OUTAGE OF GILLETTE-STATION 1.
TOTAL MILES = 3,465
Run: EWH 05/10/71
Recorded:
TOTAL LOAD = 9620 MW
MW LOSSES = 1395
MVAR LOSSES = 9937
LINE COMPENSATION:
500KV - N/A 765 KV - 80%

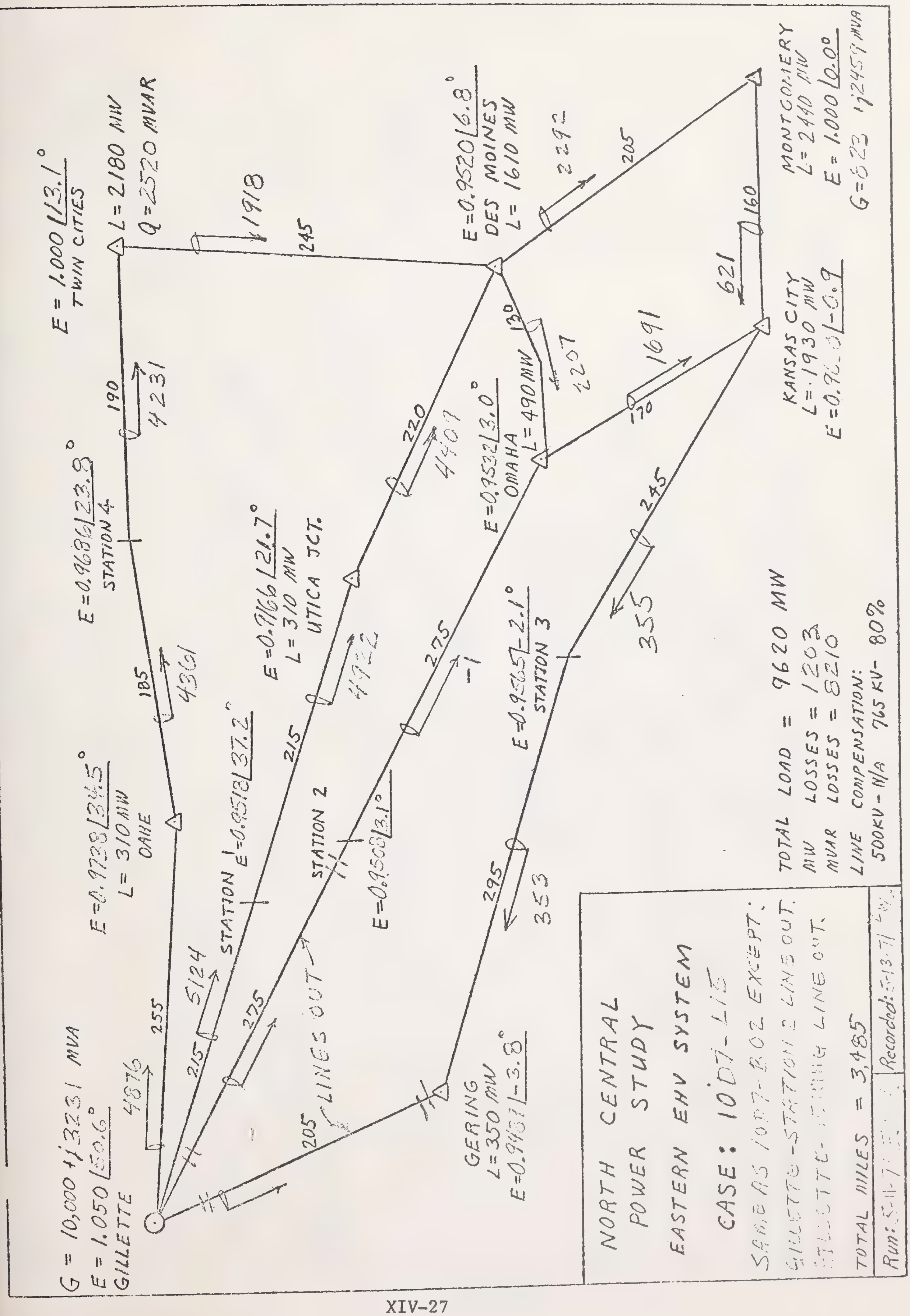


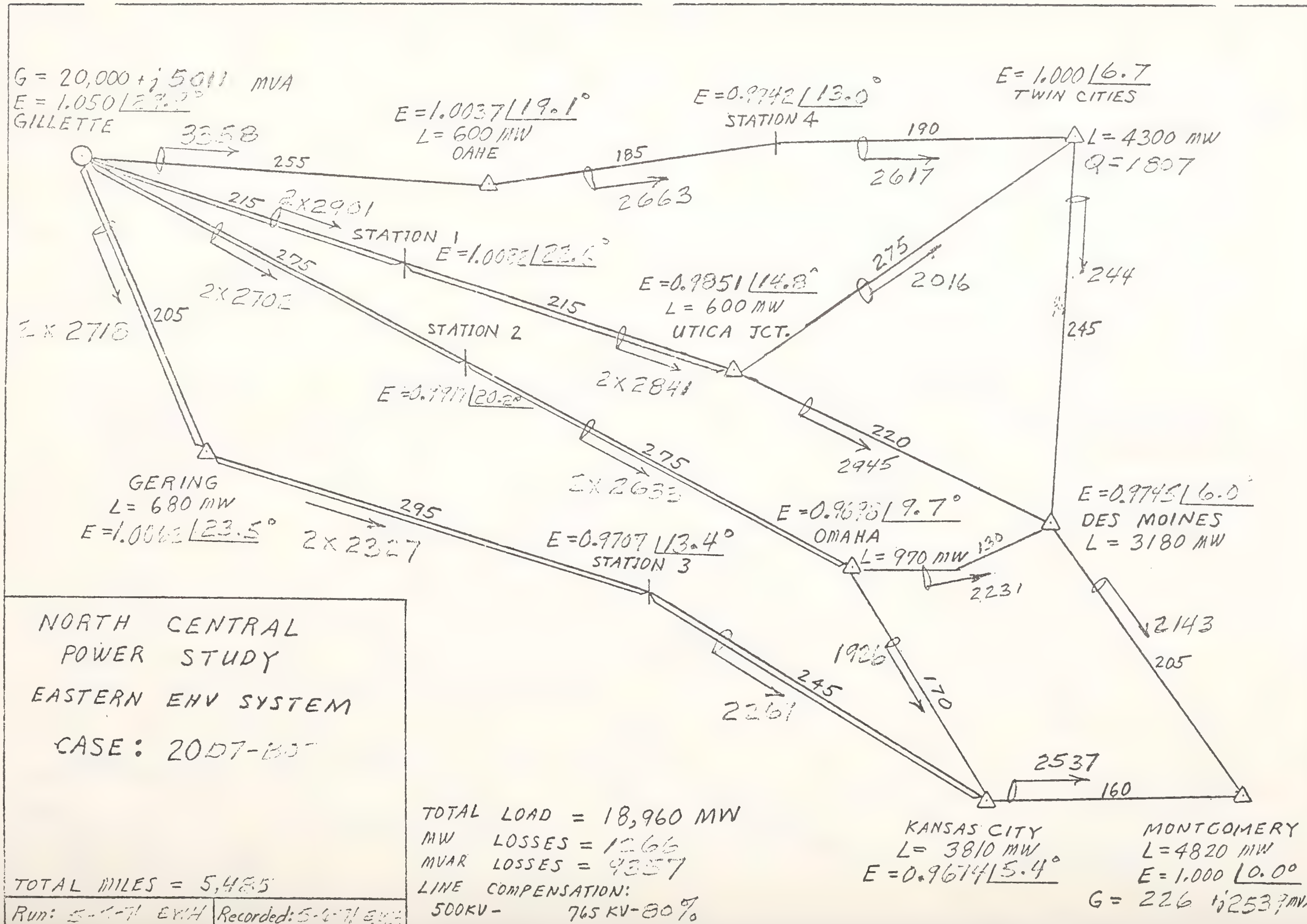
G = 10,000 + j 4120 MVA
E = 1.050 ∠43.3°
GILLETTE
E = 1.000 ∠-8.0°
TWIN CITIES
L = 2180 MW
Q = 1708. MVAR
E = 0.995 ∠-8.8°
STATION 4
E = 0.992 ∠-9.5°
L = 310 MW
OAHE
E = 0.937 ∠34.9°
STATION 1
E = 0.898 ∠17.9
L = 310 MW
UTICA JCT.
E = 0.942 ∠1.5°
DES MOINES
L = 1610 MW
E = 0.940 ∠1.7°
OMAHA
L = 490 MW
E = 0.905 ∠18.4°
STATION 3
STATION 2
GERING
L = 350 MW
KANSAS CITY
L = 1930 MW
MONTGOMERY
L = 2440 MW
E = 1.000 ∠0.0°
G = 934 + j 3266 MVA
LINE OUT
LINE OUT
4547
5453
2567
312
311
5217
4672
357
76
571
1191
3850
4042
NORTH CENTRAL POWER STUDY
EASTERN EHV SYSTEM
CASE: 10 D7 - L11
TOTAL LOAD = 9620 MW
MW LOSSES = 1314
MVAR LOSSES = 9074
LINE COMPENSATION:
500KV - N/A 765 KV - 80%
TOTAL MILES = 3,465

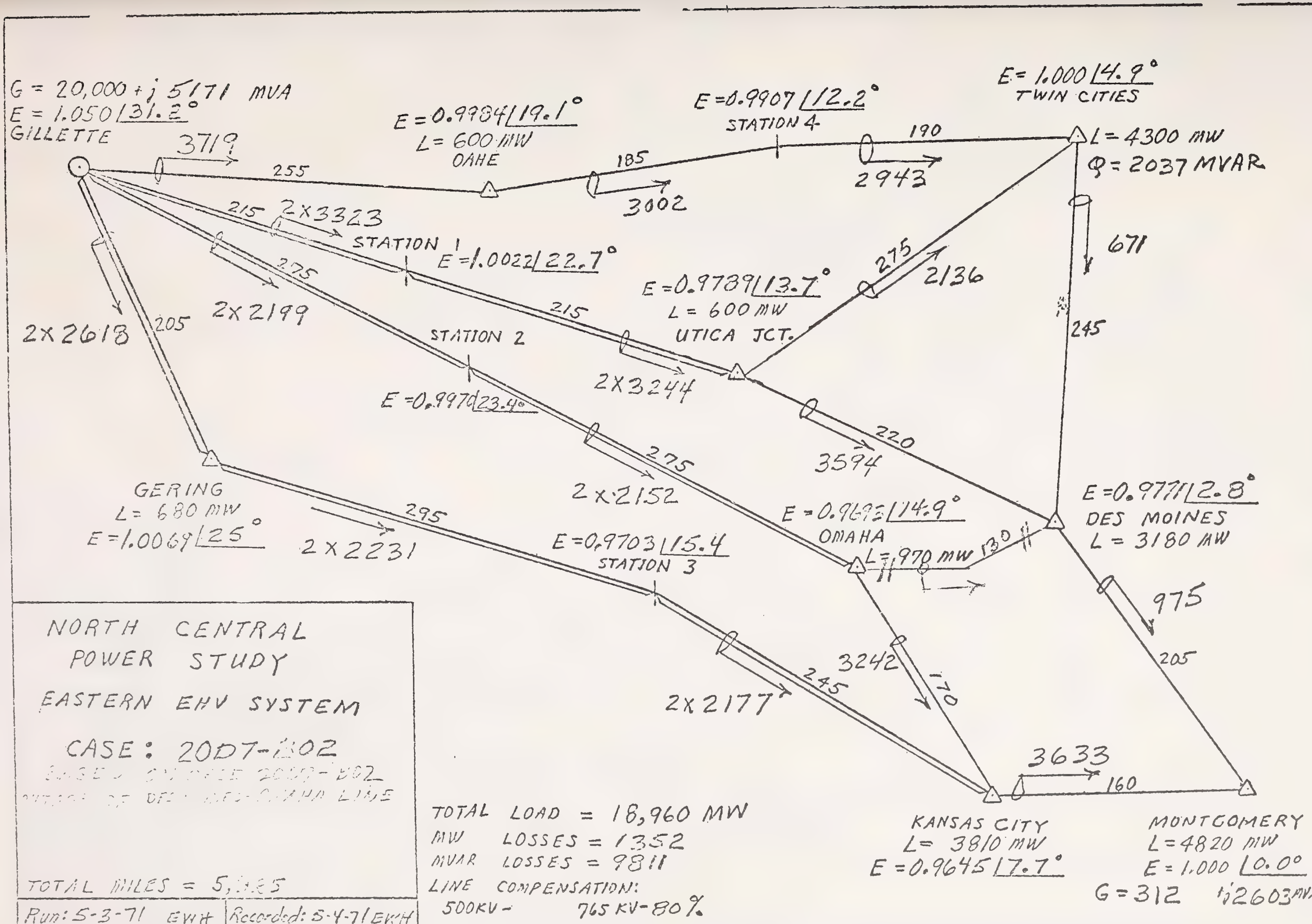

G = 10,000 +j 4055 MVA
E = 1.050 /47.9°
GILLETTE
LINE OUT
255
5031
215
275
4969
205
LINE OUT
E = 0.9924 /-6.6°
L = 310 MW
OAHE
185
311
E = 0.9954 /-5.9°
STATION 4
190
312
E = 1.000 /-5.2°
TWIN CITIES
L = 2180 MW
Q = 1768 MVAR
2569
245
STATION 1
E = 0.9472 /34.7°
215
E = 0.9094 /19.4°
L = 310 MW
UTICA JCT.
4834
220
4327
STATION 2
E = 0.9241 /28.9°
275
4717
GERING
L = 350 MW
E = 0.9313 /-2.1°
295
353
E = 0.9418 /-0.4°
STATION 3
355
245
E = 0.9260 /7.1°
OMAHA
L = 490 MW
130
1439
170
2537
E = 0.9387 /4.5°
DES MOINES
L = 1610 MW
1396
205
202
160
KANSAS CITY
L = 1930 MW
E = 0.9522 /0.9°
MONTGOMERY
L = 2440 MW
E = 1.000 /0.0°
G = 887 +j 3108 MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 10D7-L12
SAME AS 10D7-B02 EXCEPT.
GILLETTE-OAHE LINE OUT
GILLETTE-GERING LINE OUT
TOTAL MILES = 3,485
Run: 5-16-71 EWH
Recorded: 5-17-71-EWH
TOTAL LOAD = 9620 MW
MW LOSSES = 1267
MVAR LOSSES = 8931
LINE COMPENSATION:
500KV - N/A 765 KV - 80%

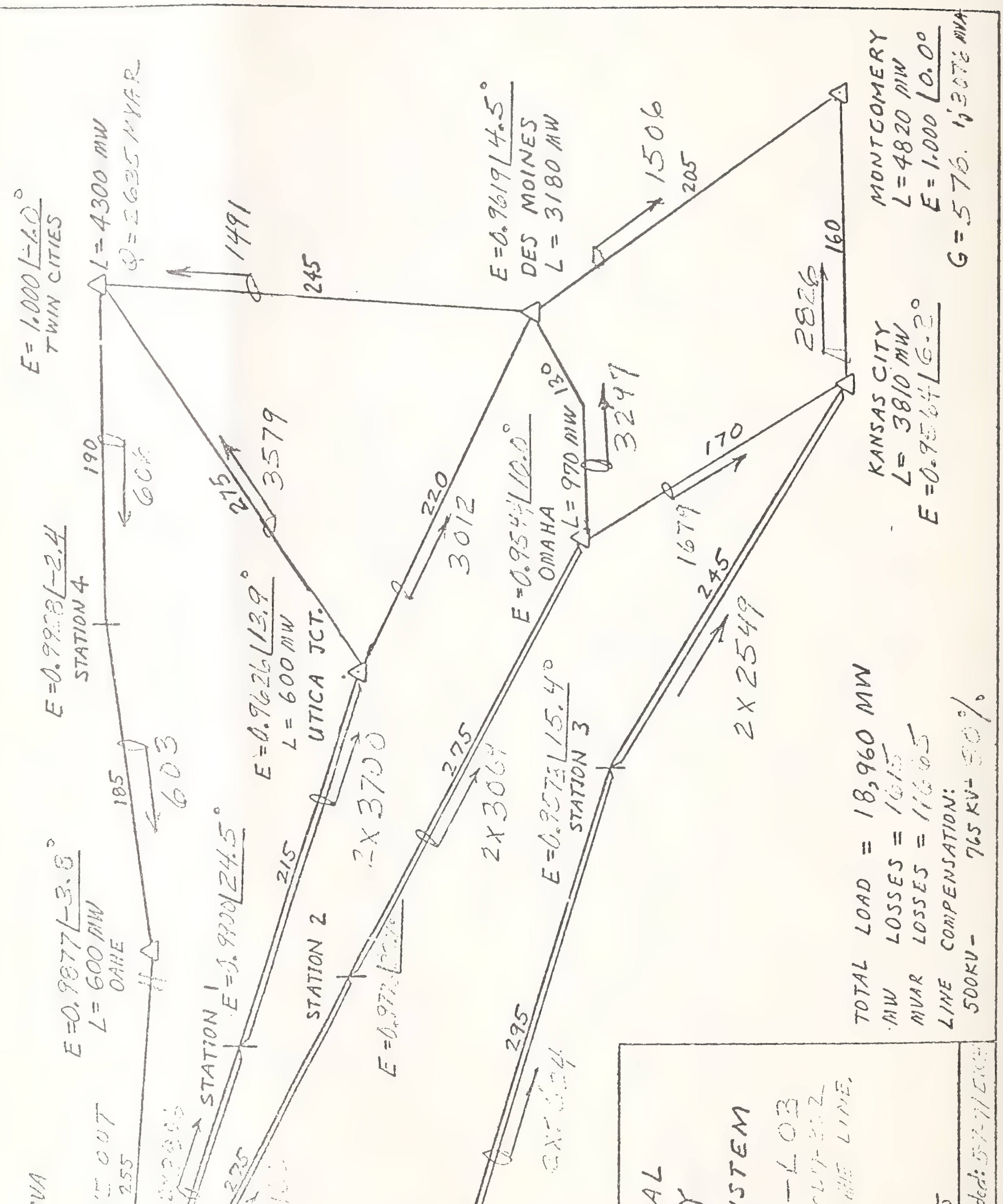

G = 10,000 + j 3463 MVA
E = 1.050 ∠50.6°
GILLETTE
E = 0.9617 ∠35.7°
L = 310 MW
OAHE
E = 0.9585 ∠20.8°
STATION 4
E = 1.000 ∠8.9°
TWIN CITIES
L = 2180 MW
Q = 2522 MVAR
255
185
190
4774
4615
2212
245
215
STATION 1
E = 0.9637 ∠0.4°
275
LINES OUT
E = 0.9694 ∠0.4°
L = 310 MW
UTICA JCT.
-1
220
312
STATION 2
4667
205
275
-1
GERING
L = 350 MW
295
4154
E = 0.9072 ∠18.7°
STATION 3
3951
245
E = 0.9622 ∠1.6°
OMAHA
L = 490 MW
130
95
589
170
E = 0.9741 ∠1.3°
DES MOINES
L = 1610 MW
399
205
1264
160
KANSAS CITY
L = 1930 MW
MONTGOMERY
L = 2440 MW
E = 1.000 ∠0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 10D7-L13
GILLETTE - STATION 1 LINE OUT.
TOTAL MILES = 3,485
TOTAL LOAD = 9620 MW
MW LOSSES = 1186
MVAR LOSSES = 8313
LINE COMPENSATION:
500KV - N/A 765 KV - 80%


G = 10,000 +j3349 MVA
E = 1.050 /48.5°
GILLETTE
4703
255
215
LINE OUT
275
5097
205
LINE OUT
E=0.9731 /32.3°
L= 310 MW
OAHE
185
4385
E=0.9681 /21.6°
STATION 4
190
4254
E = 1.000 /
TWIN CITIES
L= 2180 MW
Q=2368 MVAR
1439
245
STATION 1
E=0.9569 /3.4°
E=0.9573 /3.4°
L= 310 MW
UTICA JCT.
0
220
312
STATION 2
275
4835
GERING
L=350 MW
295
353
E=0.9486 /-0.3°
STATION 3
355
245
E=0.9400 /7.1°
OMAHA
L=490 MW
130
1495
170
2590
E=0.9621 /4.4°
DES MOINES
L= 1610 MW
1461
205
256
160
KANSAS CITY
L= 1930 MW
E=0.9590 /0.9°
MONTGOMERY
L= 2440 MW
E = 1.000 /0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 10D7-L14
SAME AS 10D7-B02 EXCEPT:
GILLETTE-STATION 1 LINE OUT.
GILLETTE-GERING LINE OUT.
TOTAL MILES = 3,485
TOTAL LOAD = 9620 MW
MW LOSSES = 1137
MVAR LOSSES = 8124
LINE COMPENSATION:
500KV - N/A 765 KV- 80%

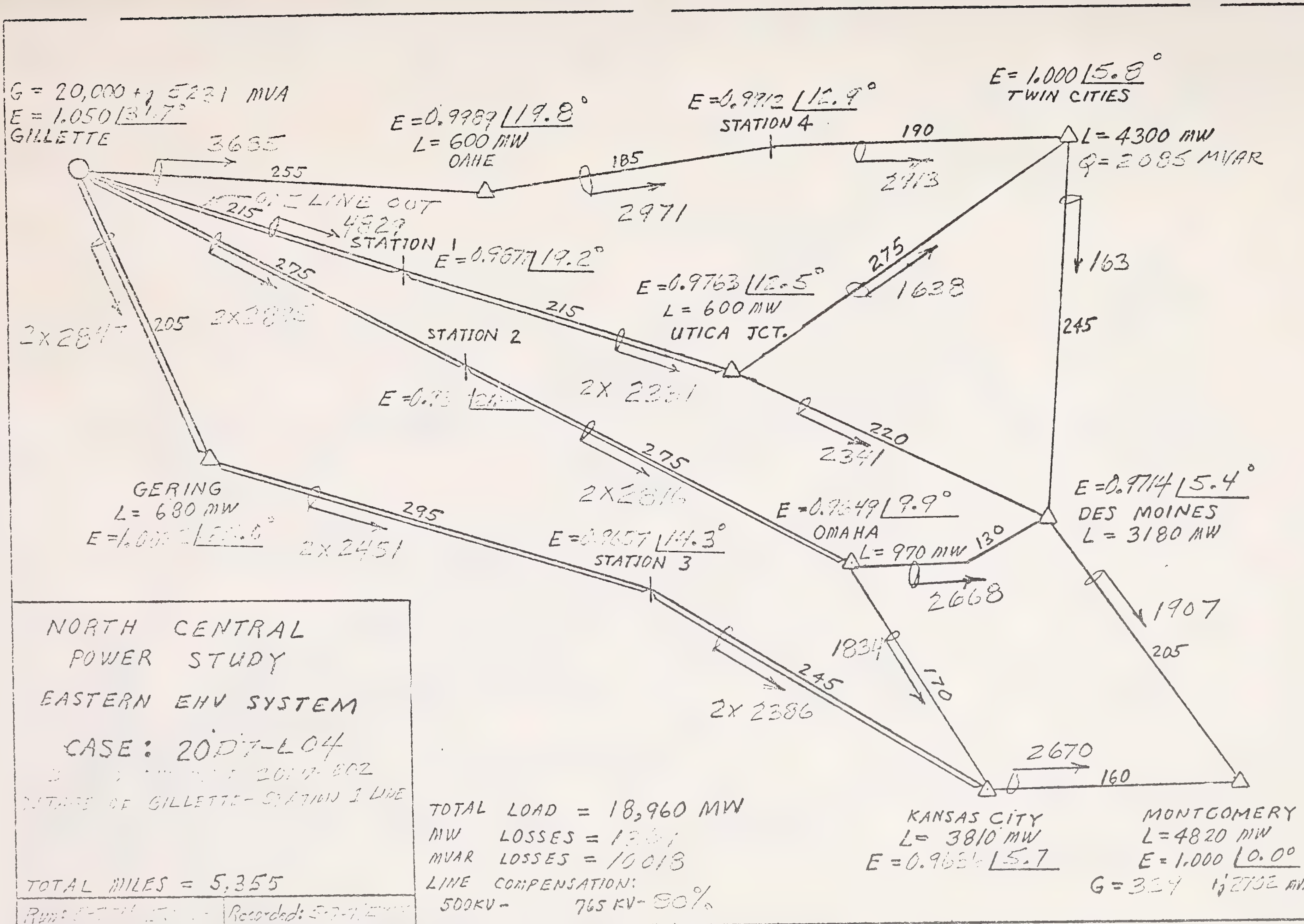

NORTH CENTRAL POWER STUDY
EASTERN EHV SYSTEM
CASE: 10D7-L15
TOTAL MILES = 3,485
TOTAL LOAD = 9620 MW
MW LOSSES = 1203
MVAR LOSSES = 8210
LINE COMPENSATION:
500KV - N/A 765 KV - 80%
G = 10,000 + j 3231 MVA
E = 1.050 /50.6°
GILLETTE
GERING
L = 350 MW
OAHE
L = 310 MW
STATION 1
STATION 2
STATION 3
STATION 4
UTICA JCT.
L = 310 MW
OMAHA
L = 490 MW
E = 1.000 /13.1°
TWIN CITIES
L = 2180 MW
Q = 2520 MVAR
DES MOINES
L = 1610 MW
E = 0.9520 /6.8°
KANSAS CITY
L = 1930 MW
MONTGOMERY
L = 2440 MW
E = 1.000 /0.0°
LINES OUT


G = 20,000 + j 5011 MVA
E = 1.050
GILLETTE
3358
255
E = 1.0037 ∠19.1°
L = 600 MW
OAHE
185
2663
E = 0.9742 ∠13.0°
STATION 4
190
2617
E = 1.000 ∠6.7
TWIN CITIES
L = 4300 MW
Q = 1807
215
2X2901
STATION 1
275
2X2702
2 x 2716
205
STATION 2
215
2X2841
E = 0.9851 ∠14.8°
L = 600 MW
UTICA JCT.
275
2016
244
245
220
2945
275
E = 0.9745 ∠6.0°
DES MOINES
L = 3180 MW
GERING
L = 680 MW
295
2 x 2327
E = 0.9707 ∠13.4°
STATION 3
E = 0.9696 ∠9.7°
OMAHA
L = 970 MW
130
2231
2143
205
1926
170
245
2261
2537
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-80
TOTAL LOAD = 18,960 MW
MW LOSSES = 1266
MVAR LOSSES = 4357
LINE COMPENSATION:
500KV - 765 KV-80%
KANSAS CITY
L = 3810 MW
E = 0.9674 ∠5.4°
MONTGOMERY
L = 4820 MW
E = 1.000 ∠0.0°
G = 226 + j2537 MVA
TOTAL MILES = 5,485
Run: 5-4-71 EWH
Recorded: 5-4-71

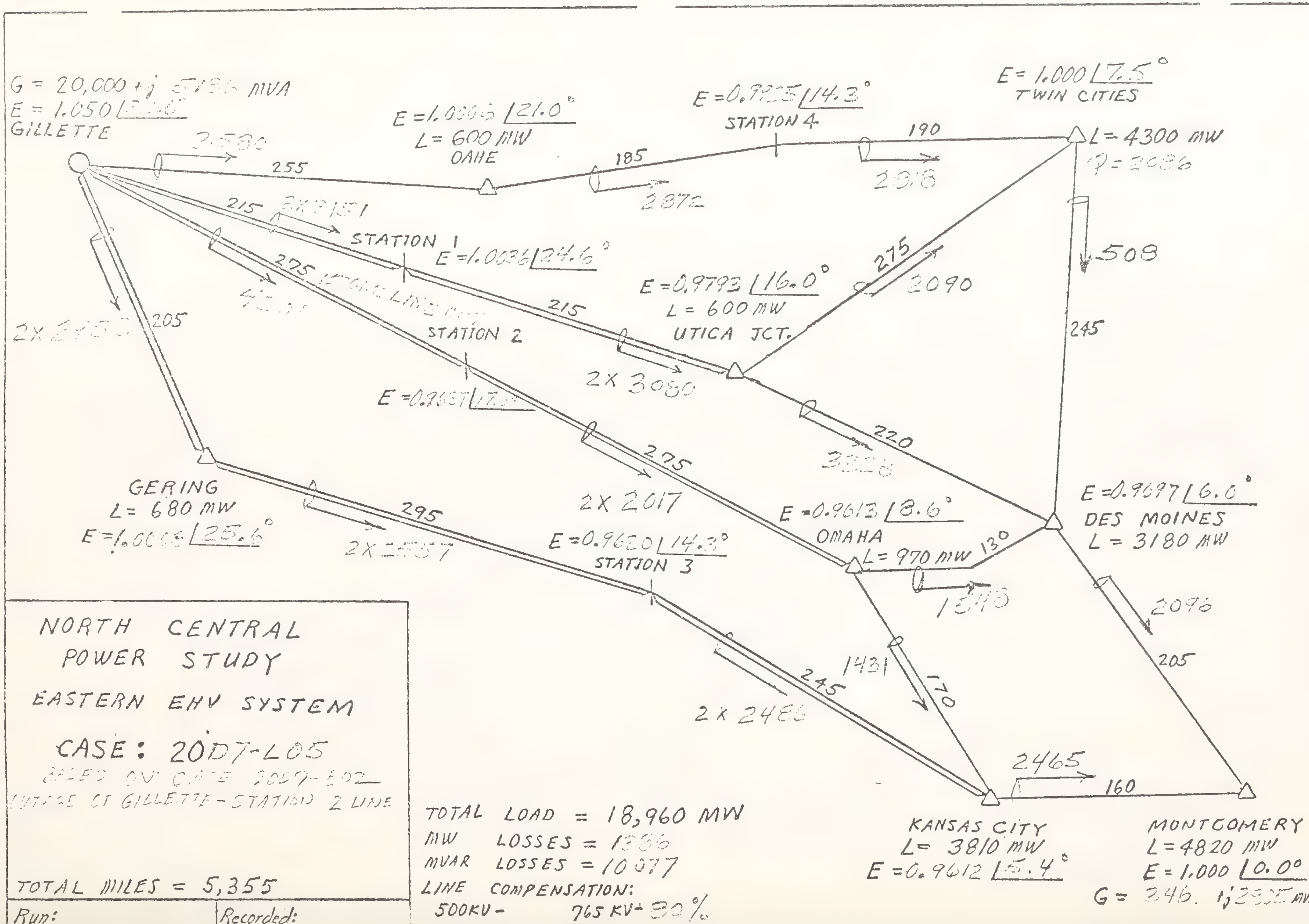

G = 20,000 + j 5171 MVA
E = 1.050 ∠31.2°
GILLETTE
3719
255
E = 0.9984 ∠19.1°
L = 600 MW
OAHE
185
3002
E = 0.9907 ∠12.2°
STATION 4
190
2943
E = 1.000 ∠4.9°
TWIN CITIES
L = 4300 MW
Q = 2037 MVAR
671
245
215
2X3323
STATION 1
E = 1.0022 ∠22.7°
275
2X2199
215
E = 0.9789 ∠13.7°
L = 600 MW
UTICA JCT.
2X3244
275
2136
2X2618
205
STATION 2
E = 0.9970 ∠23.4°
275
2X2152
220
3594
E = 0.9771 ∠2.8°
DES MOINES
L = 3180 MW
GERING
L = 680 MW
E = 1.0069 ∠25°
295
2X2231
E = 0.9703 ∠15.4
STATION 3
OMAHA
L = 970 MW
130
975
205
3242
170
245
2X2177
3633
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-
TOTAL MILES = 5,
Run: 5-3-71 EWH
Recorded: 5-4-71 EWH
TOTAL LOAD = 18,960 MW
MW LOSSES = 1352
MVAR LOSSES = 9811
LINE COMPENSATION:
500KV -
765 KV - 80%
KANSAS CITY
L = 3810 MW
E = 0.9645 ∠7.7°
MONTGOMERY
L = 4820 MW
E = 1.000 ∠0.0°
G = 312 + j2603 MVA

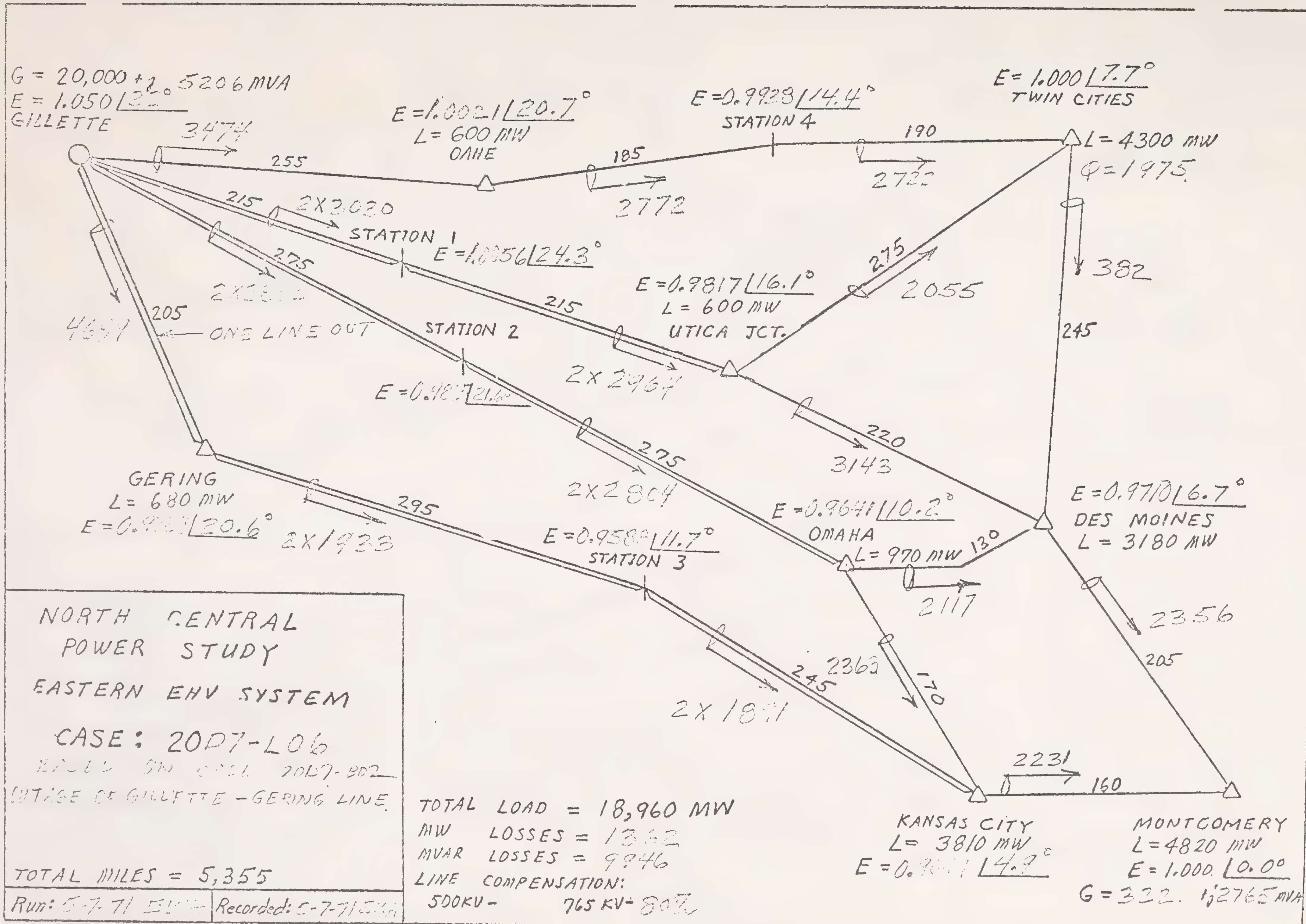


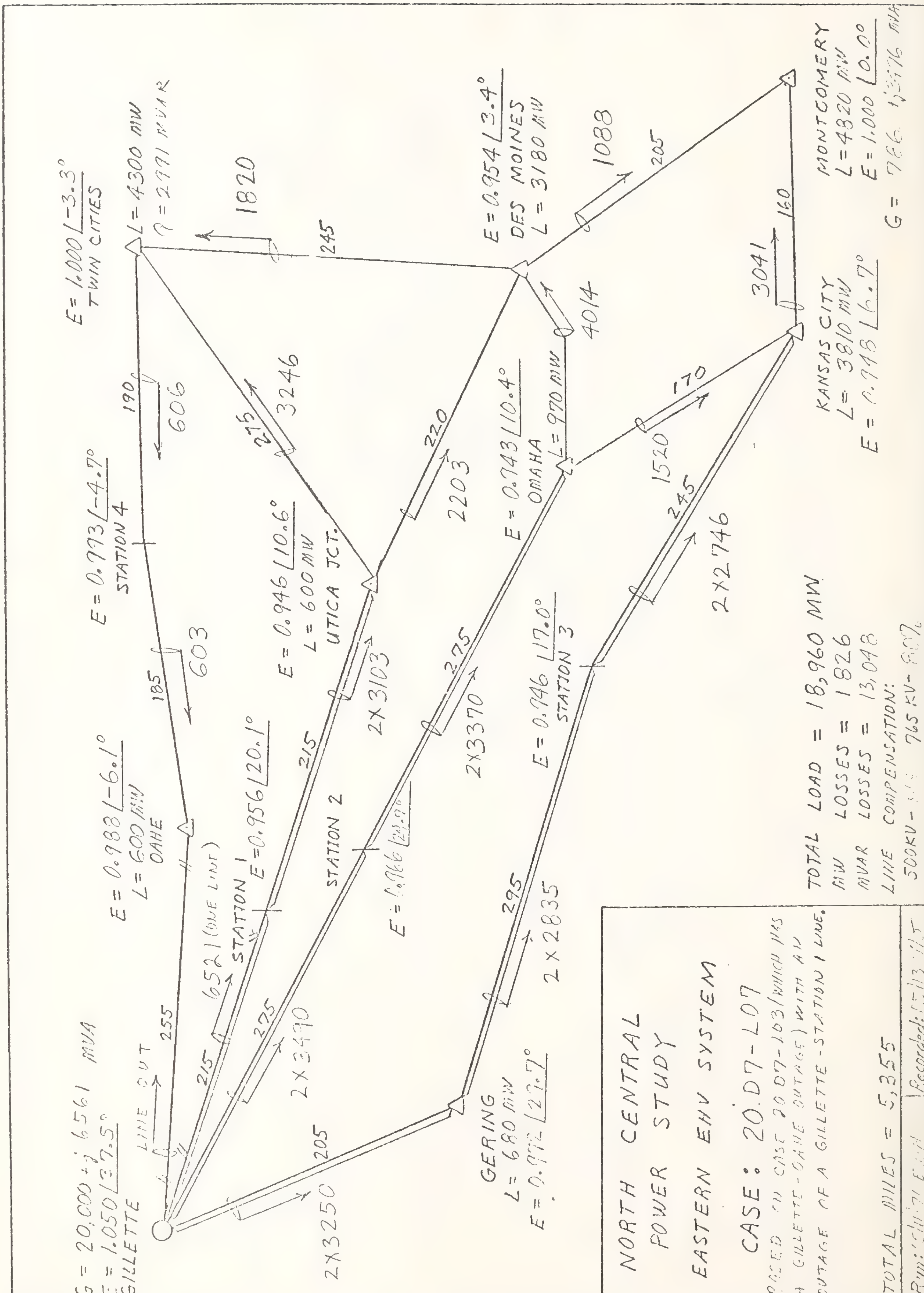
NORTH CENTRAL POWER STUDY
EASTERN EHV SYSTEM
CASE: 20.D7-L03
TOTAL MILES = 5,355
TOTAL LOAD = 18,960 MW
MW LOSSES =
MVAR LOSSES =
LINE COMPENSATION:
500KV-
765 KV-
GILLETTE
G = 20,000
E = 1.050
GERING
L = 680 MW
OAHE
L = 600 MW
E = 0.9877∠-3.8°
STATION 1
STATION 2
STATION 3
STATION 4
E = 0.9626∠13.9°
L = 600 MW
UTICA JCT.
OMAHA
L = 970 MW
E = 0.9619∠4.5°
DES MOINES
L = 3180 MW
E = 1.000∠-1.0°
TWIN CITIES
L = 4300 MW
KANSAS CITY
L = 3810 MW
MONTGOMERY
L = 4820 MW
E = 1.000∠0.0°
2X3700
2X3069
2X2549
3579
3012
3241
1506
1491
2826
1679
603
205
215
275
295
185
190
220
245
170
160

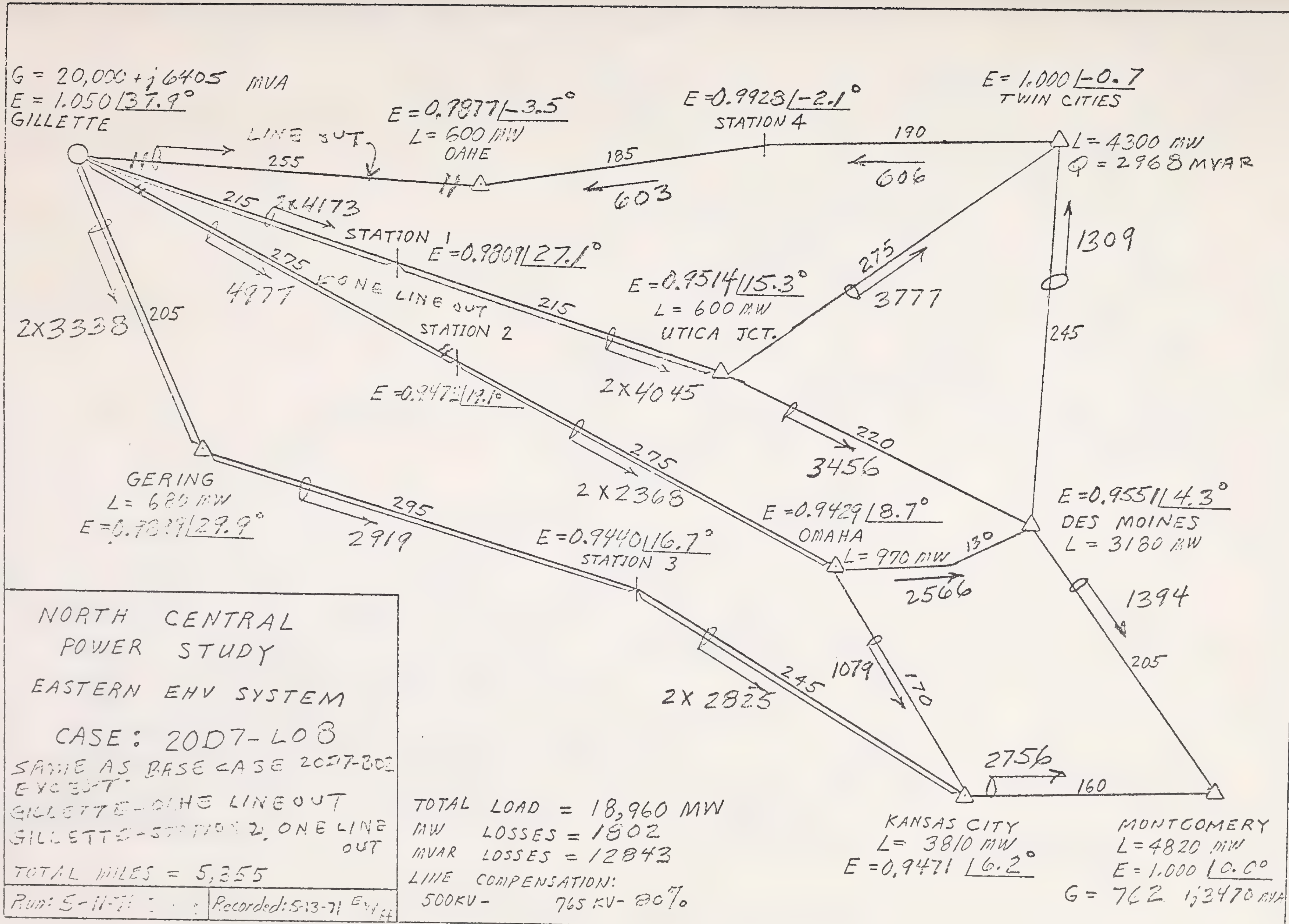


G = 20,000 + j 5231 MVA
GILLETTE
3635
255
215
LINE OUT
275
2x2847
205
E = 0.9989 /19.8°
L = 600 MW
OAHE
185
2971
E = 0.9912 /12.9°
STATION 4
190
2913
E = 1.000 /5.8°
TWIN CITIES
L = 4300 MW
163
245
STATION 1
E = 0.9677 /19.2°
215
E = 0.9763 /12.5°
L = 600 MW
UTICA JCT.
275
1638
2X 2331
220
2341
STATION 2
275
2X2816
E = 0.9714 /5.4°
DES MOINES
L = 3180 MW
E = 0.9649 /9.9°
OMAHA
L = 970 MW
130
2668
1907
205
GERING
L = 680 MW
295
2 x 2451
STATION 3
245
2X 2386
1834
170
2670
160
KANSAS CITY
L = 3810 MW
MONTGOMERY
L = 4820 MW
E = 1.000 /0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-L04
GILLETTE
TOTAL MILES = 5,355
Recorded:
TOTAL LOAD = 18,960 MW
MW LOSSES =
MVAR LOSSES = 10018
LINE COMPENSATION:
500KV -
765 KV - 80%

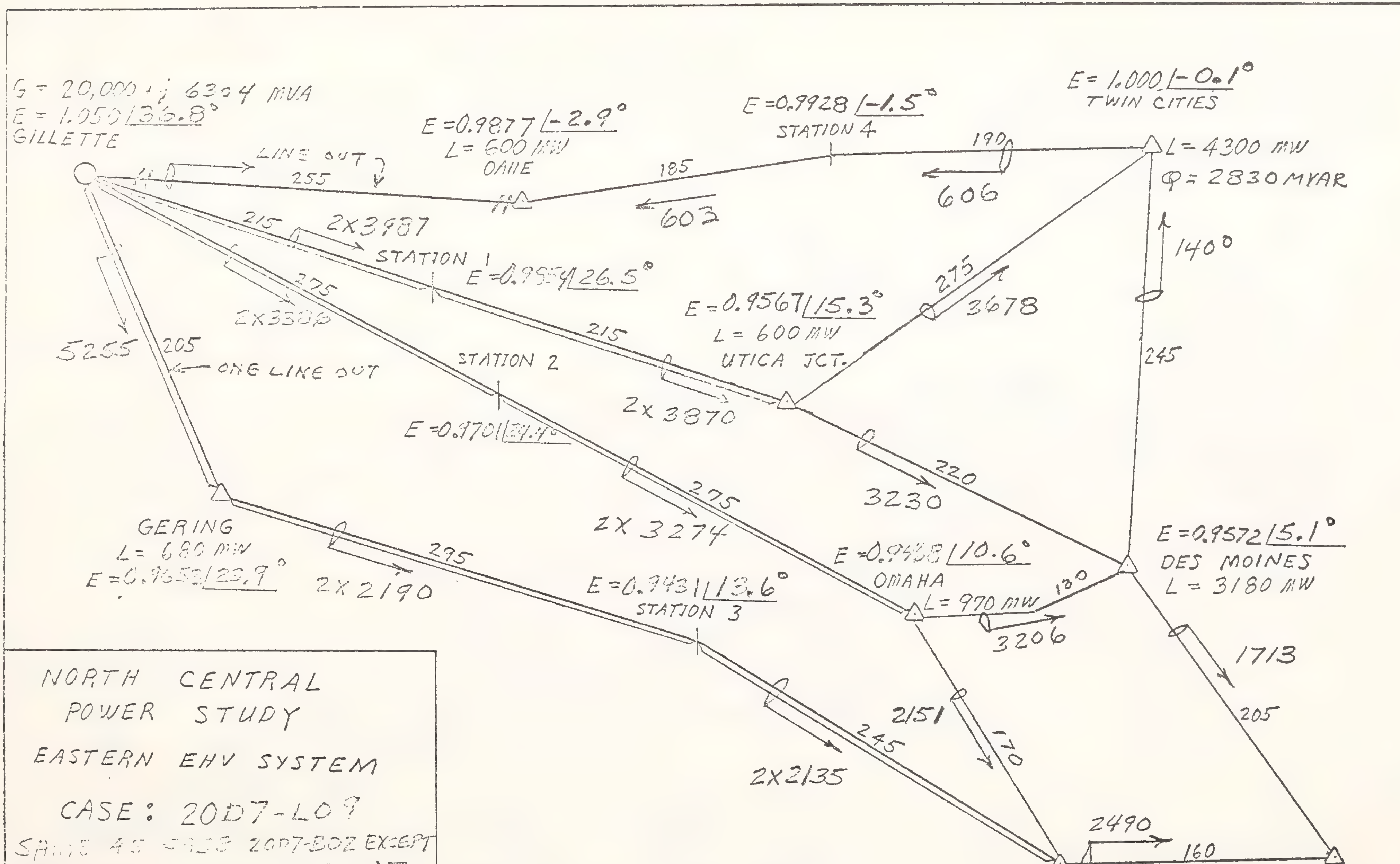

G = 20,000 + j
MVA
E = 1.050
GILLETTE
255
215
205
275
STATION 1
E = 1.0036 ∠24.6°
E = 1.0066 ∠21.0°
L = 600 MW
OAHE
185
E = 0.9925 ∠14.3°
STATION 4
190
E = 1.000 ∠7.5°
TWIN CITIES
L = 4300 MW
508
245
275
2090
E = 0.9793 ∠16.0°
L = 600 MW
UTICA JCT.
215
2X 3080
STATION 2
220
275
2X 2017
GERING
L = 680 MW
E = 1.0066 ∠25.6°
295
E = 0.9620 ∠14.3°
STATION 3
245
2 X 2486
E = 0.9613 ∠8.6°
OMAHA
L = 970 MW
130
1431
170
E = 0.9697 ∠6.0°
DES MOINES
L = 3180 MW
2096
205
2465
160
KANSAS CITY
L = 3810 MW
E = 0.9612 ∠5.4°
MONTGOMERY
L = 4820 MW
E = 1.000 ∠0.0°
G =
MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-L05
GILLETTE - STATION 2 LINE
TOTAL MILES = 5,355
Run:
Recorded:
TOTAL LOAD = 18,960 MW
MW LOSSES =
MVAR LOSSES = 10077
LINE COMPENSATION:
500KV -
765 KV - 30%


G = 20,000
E = 1.050
GILLETTE
3474
255
E = 600 MW
OAHE
185
2772
E = 0.9928 ∠14.4°
STATION 4
190
E = 1.000 ∠7.7°
TWIN CITIES
L = 4300 MW
Q = 1975
382
245
215
STATION 1
E = 24.3°
275
2X
215
E = 0.9817 ∠16.1°
L = 600 MW
UTICA JCT.
275
2055
2x 2964
220
3143
205
ONE LINE OUT
STATION 2
275
2X2804
E = 0.9710 ∠6.7°
DES MOINES
L = 3180 MW
GERING
L = 680 MW
20.6°
295
2X1933
11.7°
STATION 3
OMAHA
L = 970 MW
13°
2117
2356
205
245
170
2231
160
KANSAS CITY
L = 3810 MW
MONTGOMERY
L = 4820 MW
E = 1.000 ∠0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-L06
GILLETTE - GERING LINE.
TOTAL MILES = 5,355
Run: 5-7-71
Recorded:
TOTAL LOAD = 18,960 MW
MW LOSSES =
MVAR LOSSES =
LINE COMPENSATION:
500KV -
765 KV - 80%


G = 20,000 + j 6561 MVA
E = 1.050 |37.5°
GILLETTE
LINE OUT
255
215
275
205
2 X 3250
2 X 3490
6521 (ONE LINE)
STATION 1
E = 0.956 |20.1°
E = 0.988 |-6.1°
L = 600 MW
OAHE
185
603
E = 0.973 |-4.7°
STATION 4
190
606
E = 1.000 |-3.3°
TWIN CITIES
L = 4300 MW
Q = 2971 MVAR
1820
245
215
3246
E = 0.946 |10.6°
L = 600 MW
UTICA JCT.
2 X 3103
220
2203
E = 0.954 |3.4°
DES MOINES
L = 3180 MW
205
1088
4014
STATION 2
275
2 X 3370
E = 0.743 |10.4°
OMAHA
L = 970 MW
170
1520
GERING
L = 680 MW
295
2 X 2835
E = 0.946 |17.0°
STATION 3
245
2 X 2746
KANSAS CITY
L = 3810 MW
3041
160
MONTGOMERY
L = 4320 MW
E = 1.000 |0.0°
TOTAL LOAD = 18,960 MW
MW LOSSES = 1826
MVAR LOSSES = 13,048
LINE COMPENSATION:
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20.D7-L07
BASED ON CASE 20 D7-L03 (WHICH HAS A GILLETTE-OAHE OUTAGE) WITH AN OUTAGE OF A GILLETTE-STATION 1 LINE.
TOTAL MILES = 5,355



G = 20,000 + j6405 MVA
E = 1.050 |37.9°
GILLETTE
LINE OUT
255
E = 0.9877 |-3.5°
L = 600 MW
OAHE
185
603
E = 0.9928 |-2.1°
STATION 4
190
606
E = 1.000 |-0.7
TWIN CITIES
L = 4300 MW
Q = 2968 MVAR
1309
245
215
2x4173
STATION 1
E = 0.9809 |27.1°
275
4977
ONE LINE OUT
STATION 2
E = 0.9514 |15.3°
L = 600 MW
UTICA JCT.
275
3777
2X3338
205
2X4045
220
3456
275
2 X 2368
GERING
295
2919
E = 0.9440 |16.7°
STATION 3
E = 0.9429 |8.7°
OMAHA
L = 970 MW
130
2566
E = 0.9551 |4.3°
DES MOINES
L = 3180 MW
1394
205
245
2 X 2825
1079
170
2756
160
KANSAS CITY
L = 3810 MW
E = 0.9471 |6.2°
MONTGOMERY
L = 4820 MW
E = 1.000 |0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-L08
TOTAL MILES = 5,355
TOTAL LOAD = 18,960 MW
MW LOSSES = 1802
MVAR LOSSES = 12843
LINE COMPENSATION:
500KV -
765 KV - 80%



NORTH CENTRAL POWER STUDY

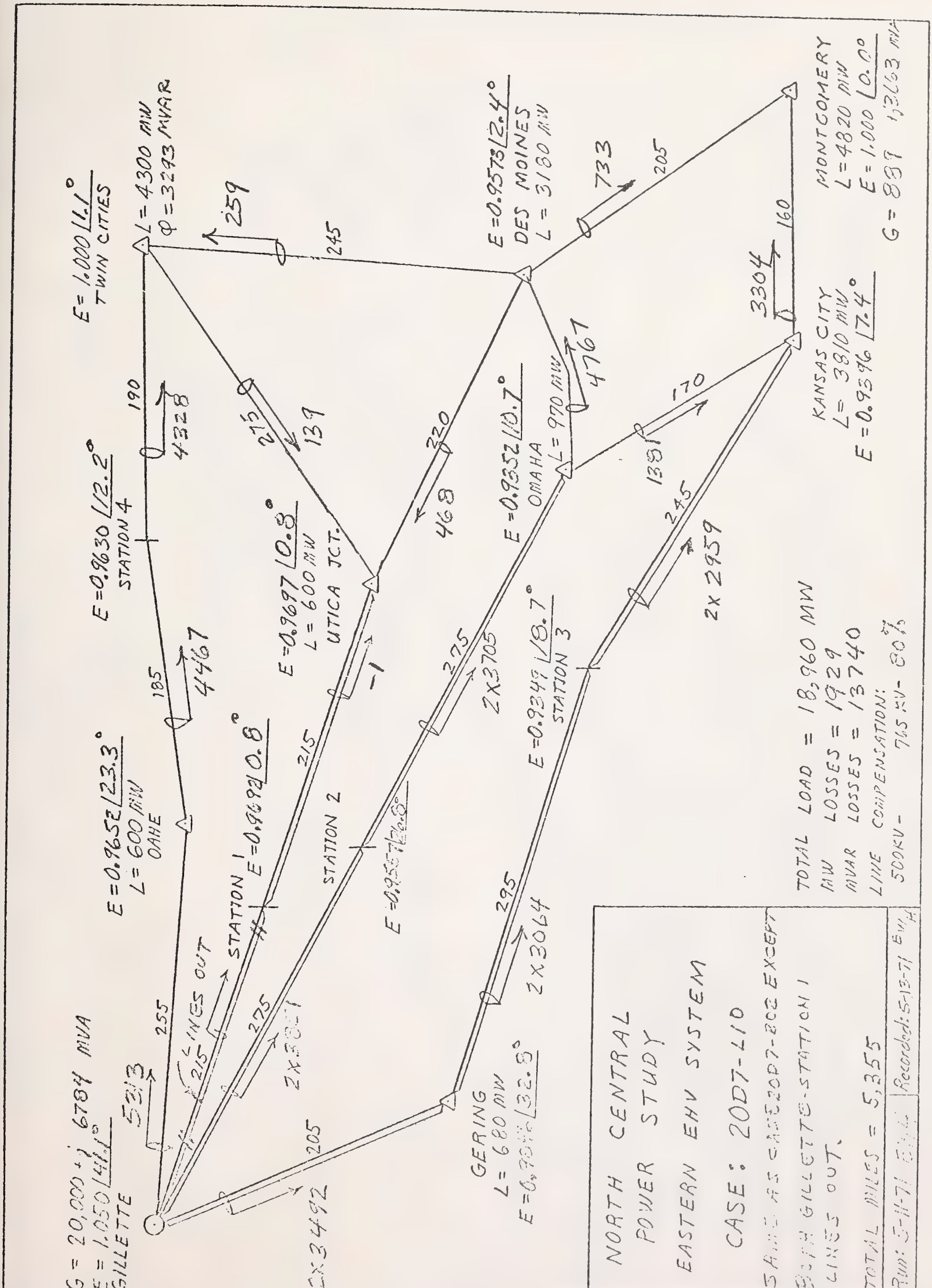
EASTERN EHV SYSTEM

CASE: 20D7-L09

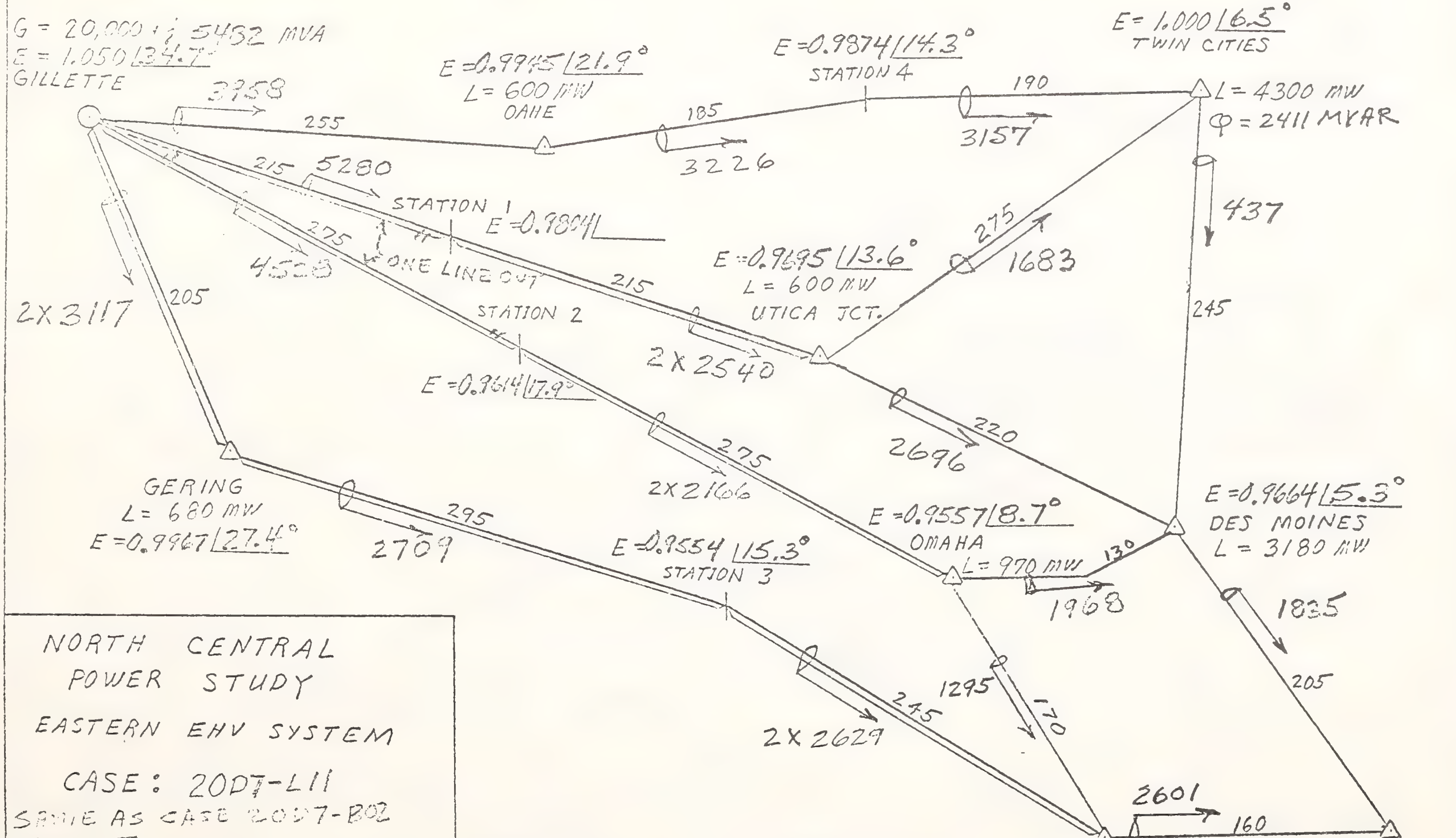
SAME AS CASE 20D7-B02 EXCEPT
GILLETTE - OAHE LINE OUT
ONE GILLETTE - GERING
LINE OUT
TOTAL MILES = 5,355

Run: 5-11-71 EWH | Recorded: 5-13-71 EWH

TOTAL LOAD = 18,960 MW
MW LOSSES = 1746
MVAR LOSSES = 12480
LINE COMPENSATION:
500KV - 765 KV - 80%



G = 20,000 + j 6784 MVA
E = 1.050 /41.1°
GILLETTE
5213
255
LINES OUT
215
275
2X 3861
205
2X 3492
E = 0.9652 /23.3°
L = 600 MW
OAHE
185
4467
E = 0.9630 /12.2°
STATION 4
190
4328
E = 1.000 /1.1°
TWIN CITIES
L = 4300 MW
Q = 3293 MVAR
259
245
215
139
STATION 1
E = 0.9692 /0.8°
215
-1
E = 0.9697 /0.8°
L = 600 MW
UTICA JCT.
220
468
E = 0.9573 /2.4°
DES MOINES
L = 3180 MW
733
205
STATION 2
275
2X3705
E = 0.9352 /10.7°
OMAHA
L = 970 MW
4767
GERING
L = 680 MW
295
2X3064
E = 0.9349 /8.7°
STATION 3
245
2X 2959
138
170
3304
160
KANSAS CITY
L = 3810 MW
E = 0.9396 /7.4°
MONTGOMERY
L = 4820 MW
E = 1.000 /0.0°
G = 887 - j 3263 MVA
TOTAL LOAD = 18,960 MW
MW LOSSES = 1929
MVAR LOSSES = 13740
LINE COMPENSATION:
500KV -
765 KV - 80%
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-L10
SAME AS CASE 20D7-BC2 EXCEPT
BOTH GILLETTE-STATION 1
LINES OUT.
TOTAL MILES = 5,355
Run: 5-11-71
Recorded: 5-13-71



NORTH CENTRAL
POWER STUDY

EASTERN EHV SYSTEM

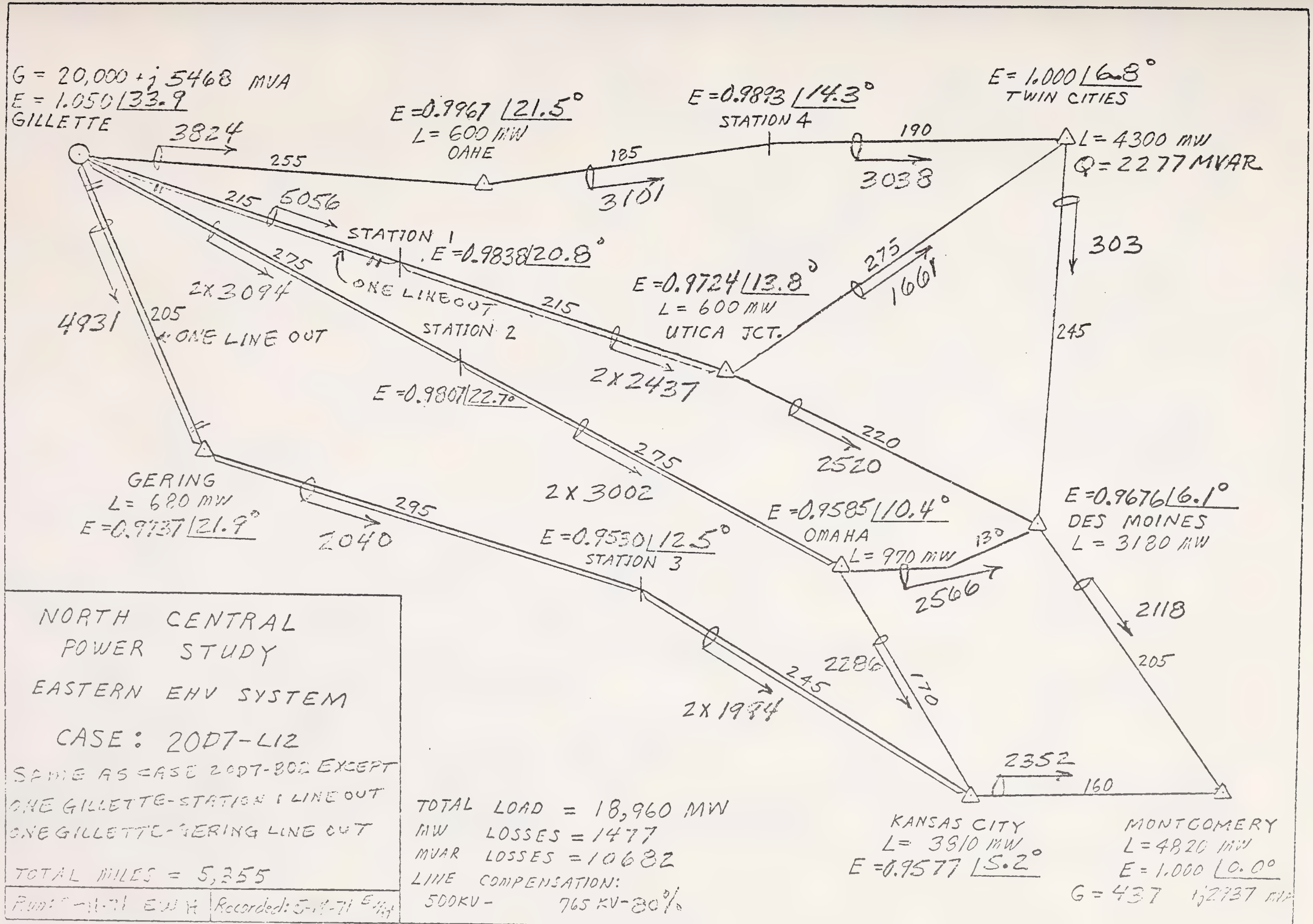
CASE: 20D7-L11

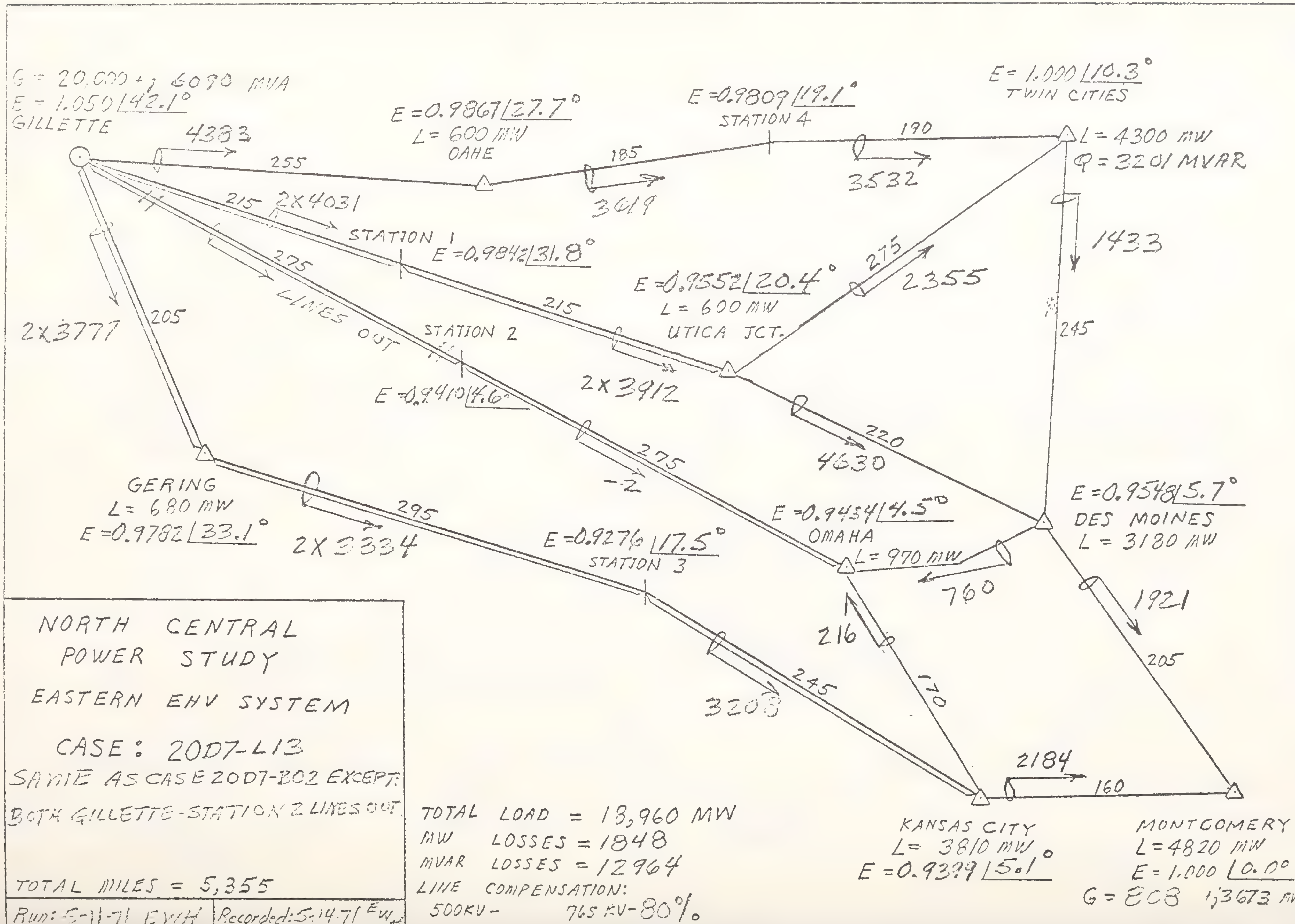
SAME AS CASE 20D7-B02 EXCEPT.
ONE GILLETTE - STATION 1 LINE OUT
" " - STATION 2 LINE OUT

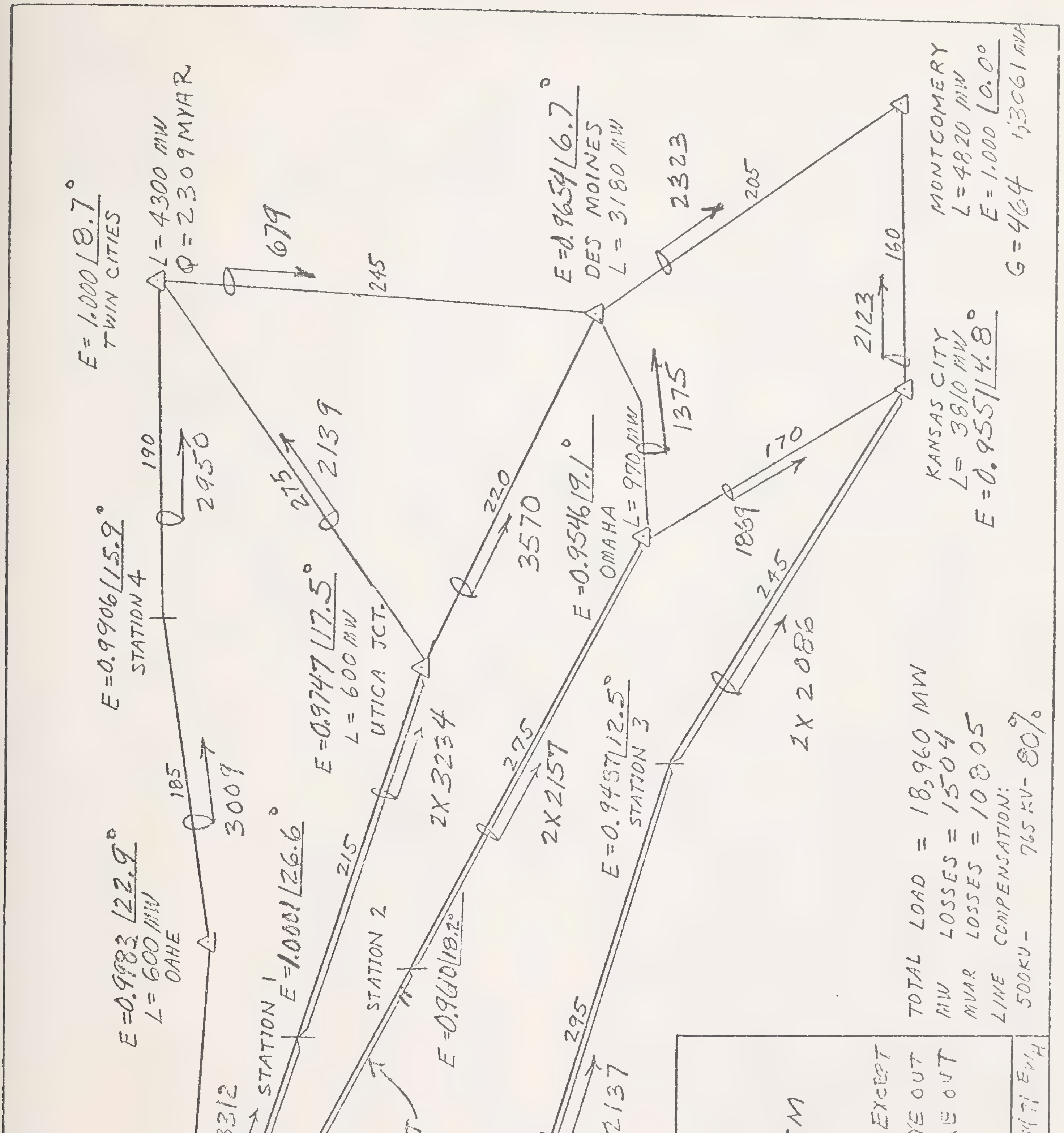
TOTAL MILES = 5,355

Run: 5-11-71 E.W.H | Recorded: 5-14-71 EWH

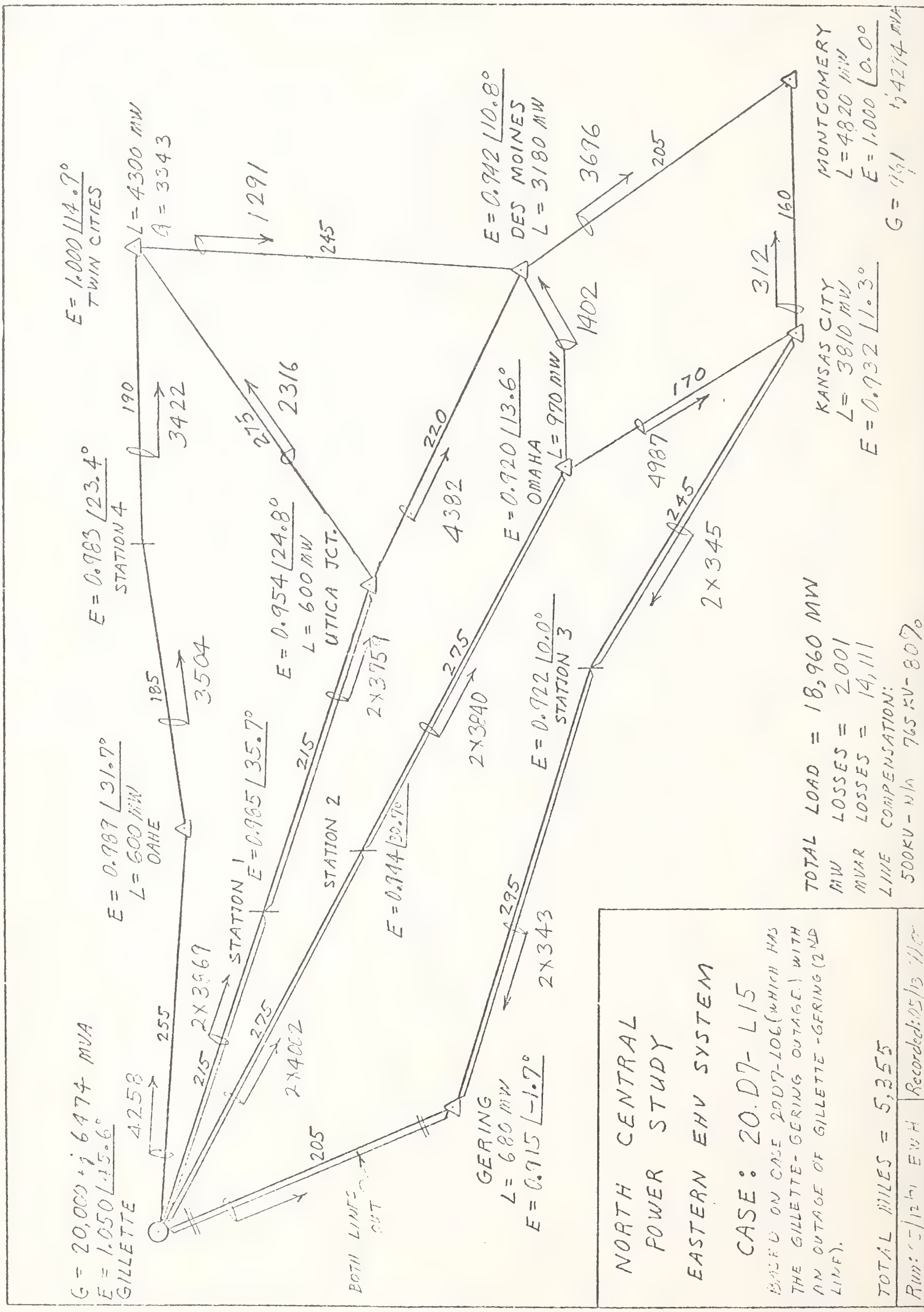
TOTAL LOAD = 18,960 MW
MW LOSSES = 1512
MVAR LOSSES = 10891
LINE COMPENSATION:
500KV - 765 KV - 80%

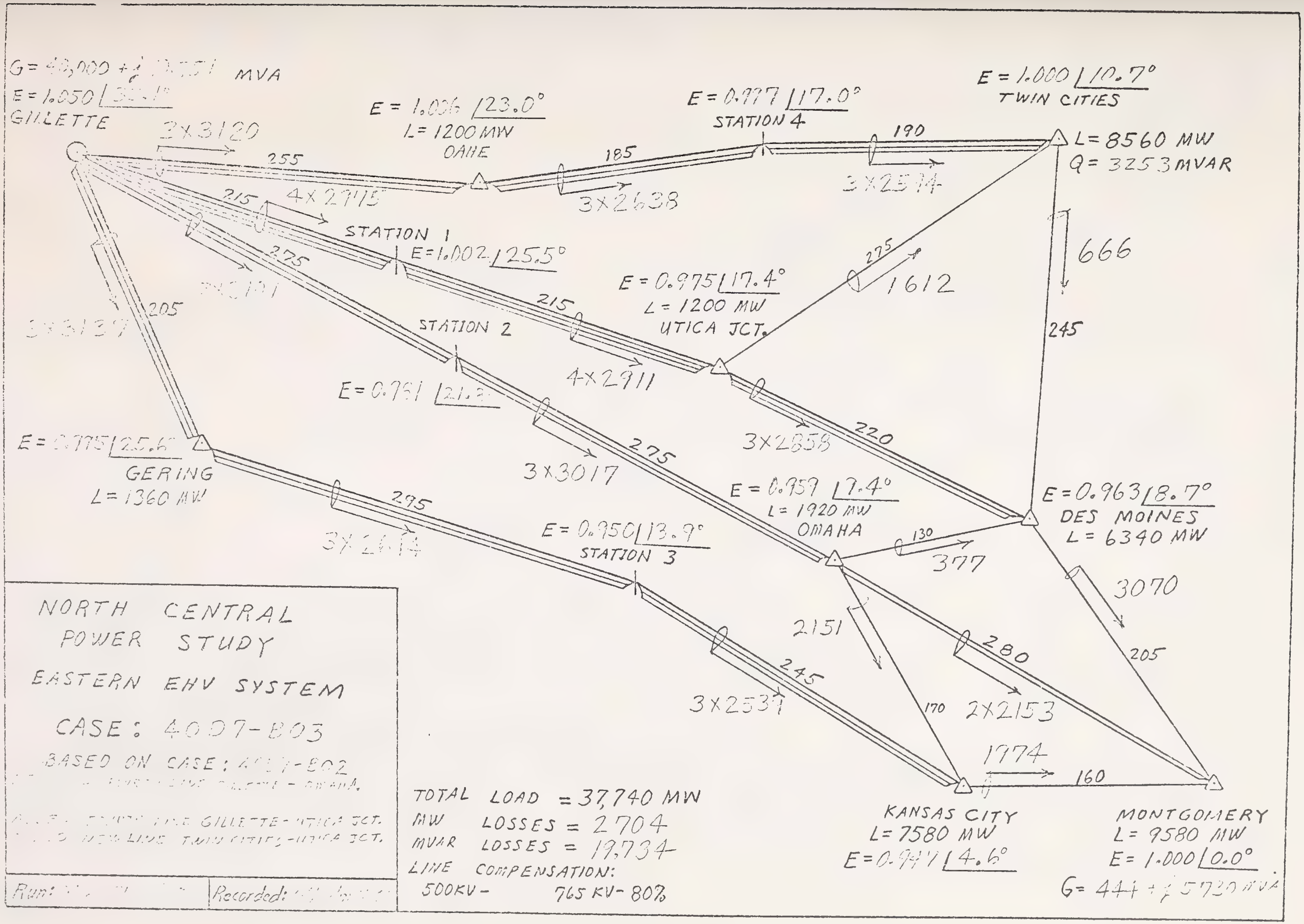

G = 20,000 + j 5468 MVA
E = 1.050 /33.9
GILLETTE
3824
255
215
5056
275
2X 3094
4931
205
ONE LINE OUT
E = 0.9967 /21.5°
L = 600 MW
OAHE
185
3101
E = 0.9893 /14.3°
STATION 4
190
3038
E = 1.000 /6.8°
TWIN CITIES
L = 4300 MW
Q = 2277 MVAR
303
245
STATION 1
E = 0.9838 /20.8°
ONE LINE OUT
215
E = 0.9724 /13.8°
L = 600 MW
UTICA JCT.
2X 2437
275
1661
STATION 2
E = 0.9807 /22.7°
275
2X 3002
220
2520
GERING
L = 680 MW
E = 0.9737 /21.9°
295
2040
E = 0.9530 /12.5°
STATION 3
E = 0.9585 /10.4°
OMAHA
L = 970 MW
130
2566
E = 0.9676 /6.1°
DES MOINES
L = 3180 MW
2118
205
2286
170
245
2X 1974
2352
160
KANSAS CITY
L = 3910 MW
E = 0.9577 /5.2°
MONTGOMERY
L = 4820 MW
E = 1.000 /0.0°
G = 437 j2737 MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-L12
SAME AS CASE 20D7-B02 EXCEPT
ONE GILLETTE-STATION 1 LINE OUT
ONE GILLETTE-GERING LINE OUT
TOTAL MILES = 5,355
TOTAL LOAD = 18,960 MW
MW LOSSES = 1477
MVAR LOSSES = 10682
LINE COMPENSATION:
500KV - 765 KV - 80%

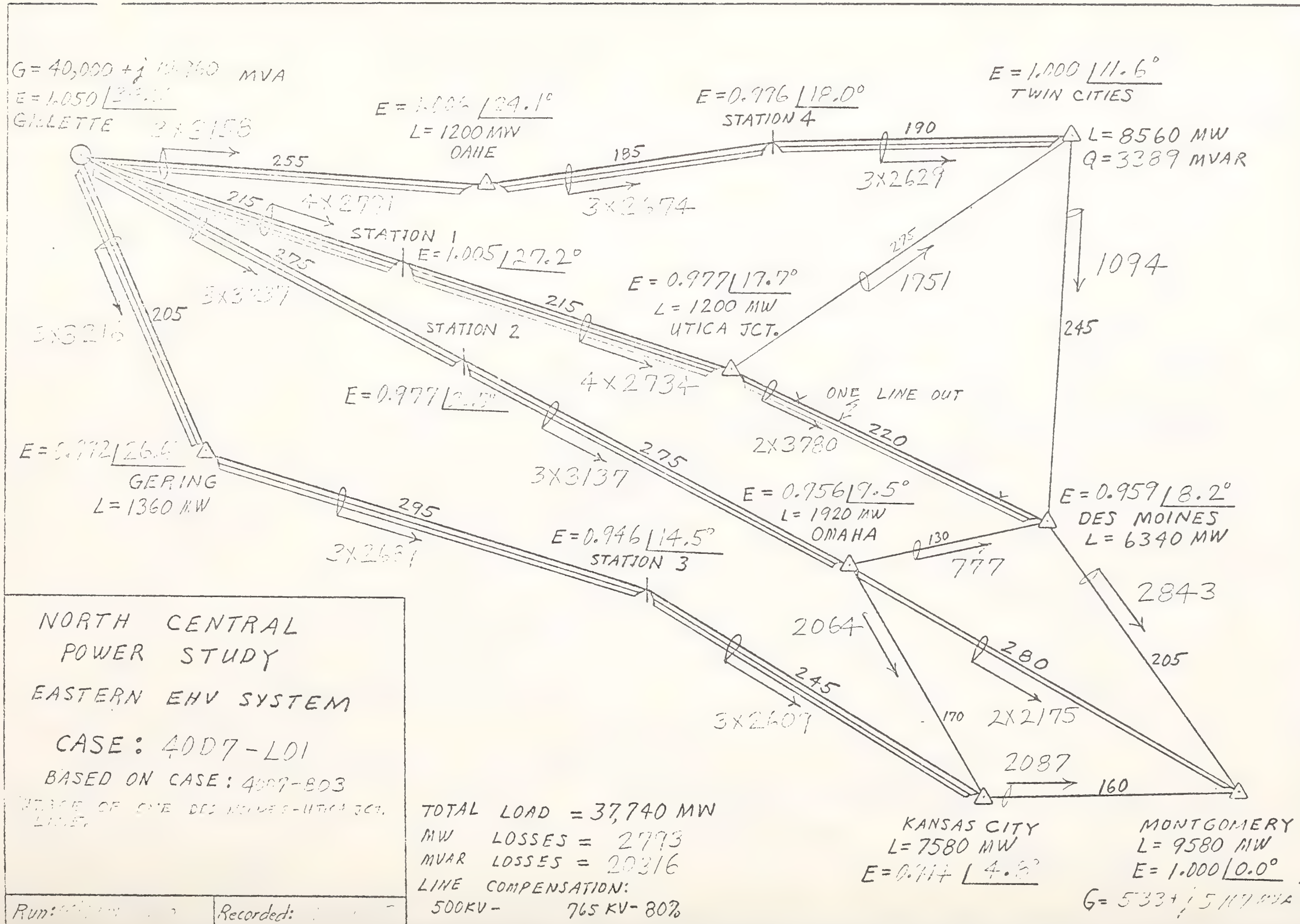

G = 20,000 + j 6090 MVA
E = 1.050 |42.1°
GILLETTE
4383
255
E = 0.9867 |27.7°
L = 600 MW
OAHE
185
3619
E = 0.9809 |19.1°
STATION 4
190
3532
E = 1.000 |10.3°
TWIN CITIES
L = 4300 MW
Q = 3201 MVAR
1433
245
215
2X4031
STATION 1
E = 0.9842 |31.8°
275
LINES OUT
STATION 2
E = 0.9410 |16.6°
215
2X3912
E = 0.9552 |20.4°
L = 600 MW
UTICA JCT.
275
2355
220
4630
2X3777
205
GERING
L = 680 MW
E = 0.9782 |33.1°
295
2X3334
-2
275
E = 0.9276 |17.5°
STATION 3
245
3208
E = 0.9454 |4.5°
OMAHA
L = 970 MW
760
216
170
E = 0.9548 |5.7°
DES MOINES
L = 3180 MW
1921
205
2184
160
KANSAS CITY
L = 3810 MW
E = 0.9399 |5.1°
MONTGOMERY
L = 4820 MW
E = 1.000 |0.0°
G = 8C8 + j3673 MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-L13
SAME AS CASE 20D7-B02 EXCEPT:
BOTH GILLETTE-STATION 2 LINES OUT
TOTAL MILES = 5,355
Run: 5-11-71 EWH
Recorded: 5-14-71 EWH
TOTAL LOAD = 18,960 MW
MW LOSSES = 1848
MVAR LOSSES = 12964
LINE COMPENSATION:
500KV -
765 KV - 80%



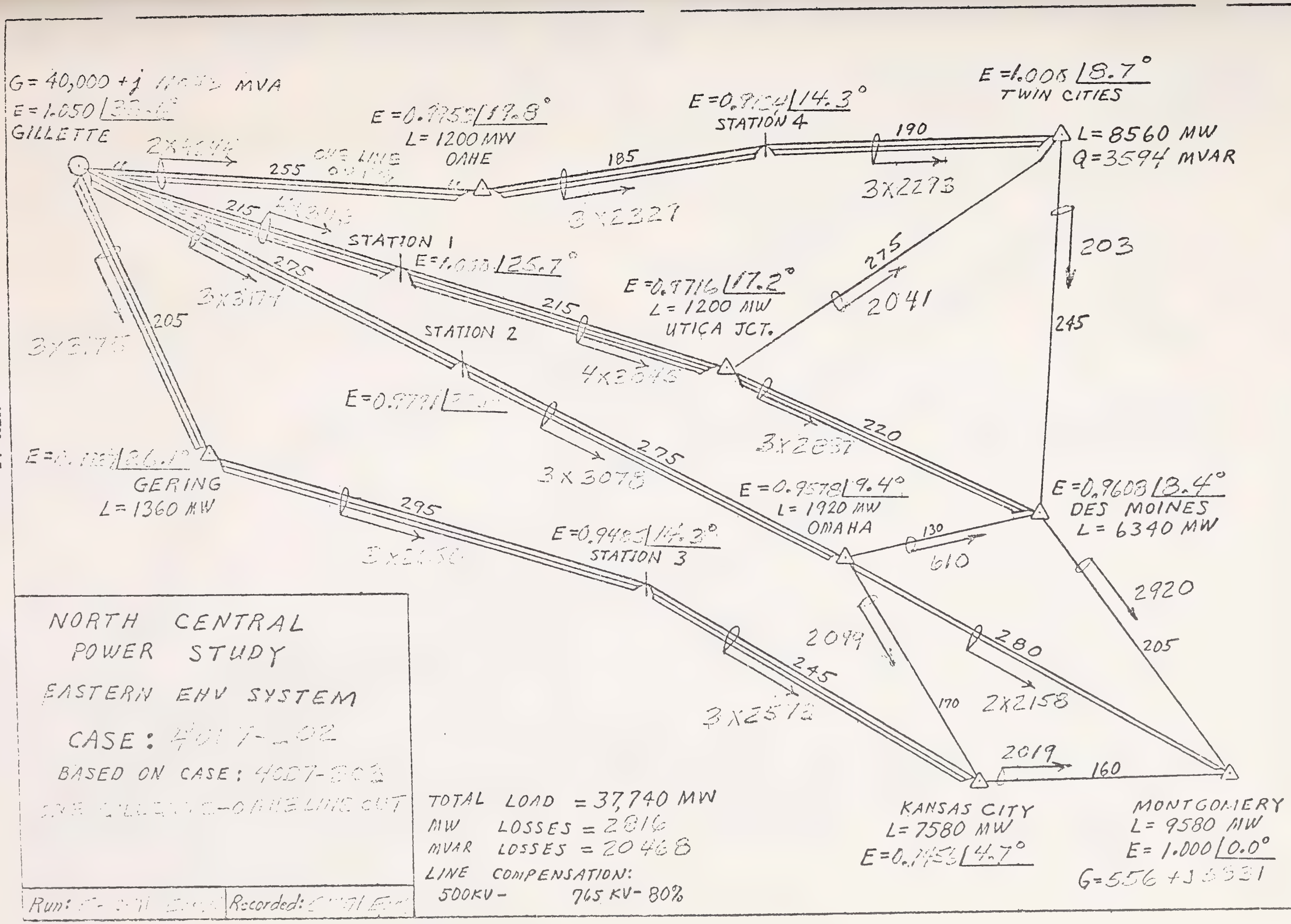
G = 20,000 + j 5435 MVA
E = 1.050 /35°
GILLETTE
E = 1.000 /8.7°
TWIN CITIES
L = 4300 MW
Q = 2309 MVAR
E = 0.9906 /15.9°
STATION 4
E = 0.9983 /22.9°
L = 600 MW
OAHE
E = 0.9747 /17.5°
L = 600 MW
UTICA JCT.
E = 1.0001 /26.6°
STATION 1
STATION 2
E = 0.9610 /18.2°
ONE LINE OUT
E = 0.9654 /6.7°
DES MOINES
L = 3180 MW
E = 0.9546 /9.1°
OMAHA
L = 970 MW
E = 0.9457 /12.5°
STATION 3
GERING
L = 680 MW
KANSAS CITY
L = 3810 MW
E = 0.9551 /4.8°
MONTGOMERY
L = 4820 MW
E = 1.000 /0.0°
G = 4644 j 3061 MVA
3726
255
215
2X3312
275
4508
205
5141
2X2137
295
185
3009
190
2950
215
2139
245
679
220
3570
2X3234
275
2X2157
245
2X2086
1859
170
1375
205
2323
2123
160
TOTAL LOAD = 18,960 MW
MW LOSSES = 1504
MVAR LOSSES = 10805
LINE COMPENSATION:
500 KV - 765 KV - 80%
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20D7-L/4
SAME AS CASE 20D7-B02 EXCEPT
ONE GILLETTE-STATION 2 LINE OUT
ONE GILLETTE-GERING LINE OUT
TOTAL MILES = 5,355
Run: 5-11-71 E.W.H.
Recorded: 5-11-71 E.W.H.

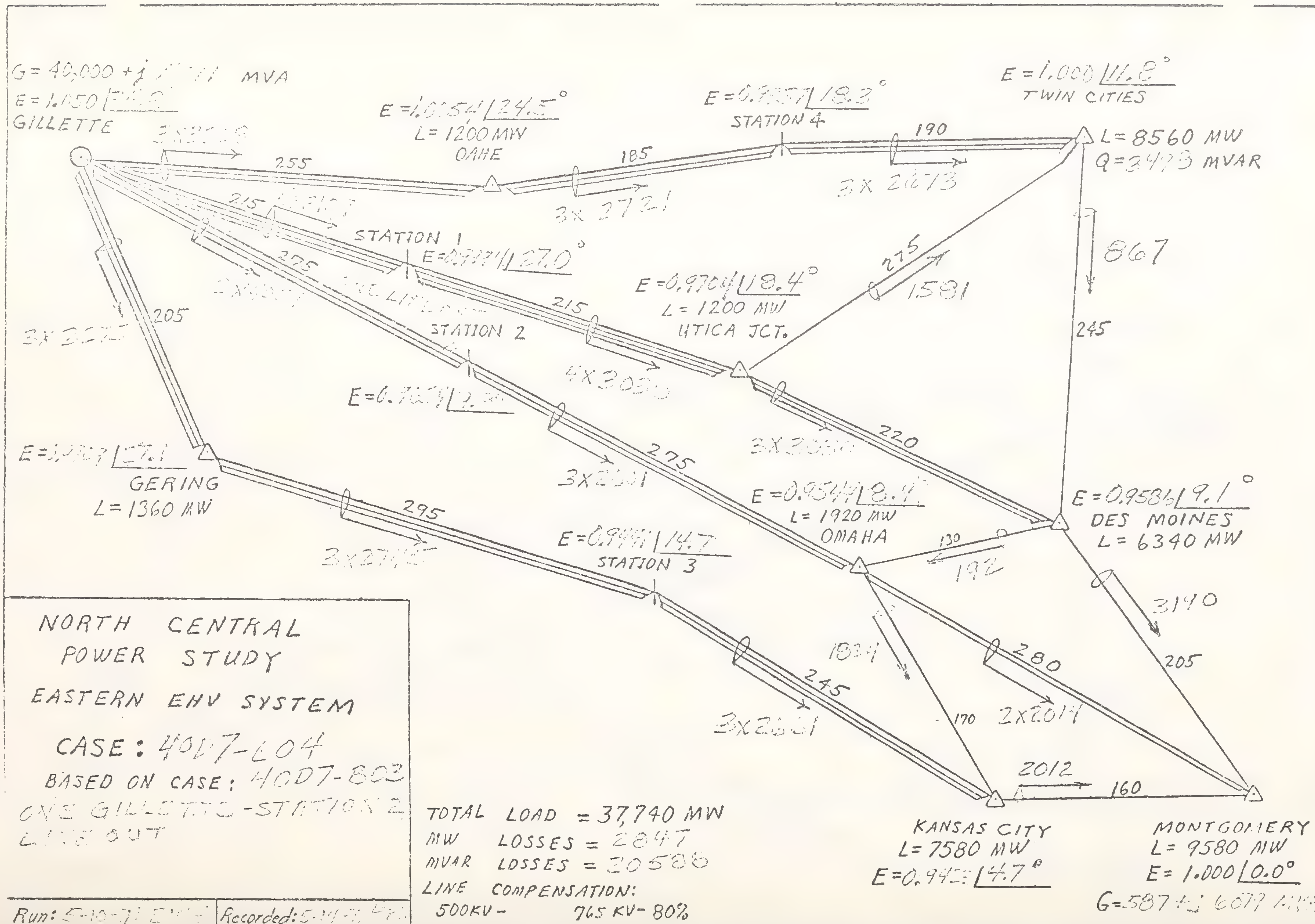

G = 20,000 + j 6474 MVA
E = 1.050 ∠15.6°
GILLETTE
4258
255
2X3967
215
275
2X4002
205
BOTH LINES OUT
E = 0.987 ∠31.7°
L = 600 MW
OAHE
185
3504
E = 0.983 ∠23.4°
STATION 4
190
3422
E = 1.000 ∠14.7°
TWIN CITIES
L = 4300 MW
Q = 3343
1291
245
STATION 1
E = 0.965 ∠35.7°
215
2X3757
E = 0.954 ∠24.8°
L = 600 MW
UTICA JCT.
215
2316
220
4382
STATION 2
E = 0.944
275
2X3840
E = 0.920 ∠13.6°
OMAHA
L = 970 MW
E = 0.942 ∠10.8°
DES MOINES
L = 3180 MW
1402
3676
205
GERING
L = 680 MW
E = 0.915 ∠-1.7°
295
2X343
E = 0.922 ∠10.0°
STATION 3
245
2X345
4987
170
312
160
KANSAS CITY
L = 3810 MW
E = 0.932 ∠1.3°
MONTGOMERY
L = 4820 MW
E = 1.000 ∠0.0°
TOTAL LOAD = 18,960 MW
MW LOSSES = 2001
MVAR LOSSES = 14,111
LINE COMPENSATION:
500KV - N/A 765KV - 80%
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 20.D7-L15
BASED ON CASE 20D7-L06 (WHICH HAS THE GILLETTE-GERING OUTAGE) WITH AN OUTAGE OF GILLETTE-GERING (2ND LINE).
TOTAL MILES = 5,355
Run:
Recorded:

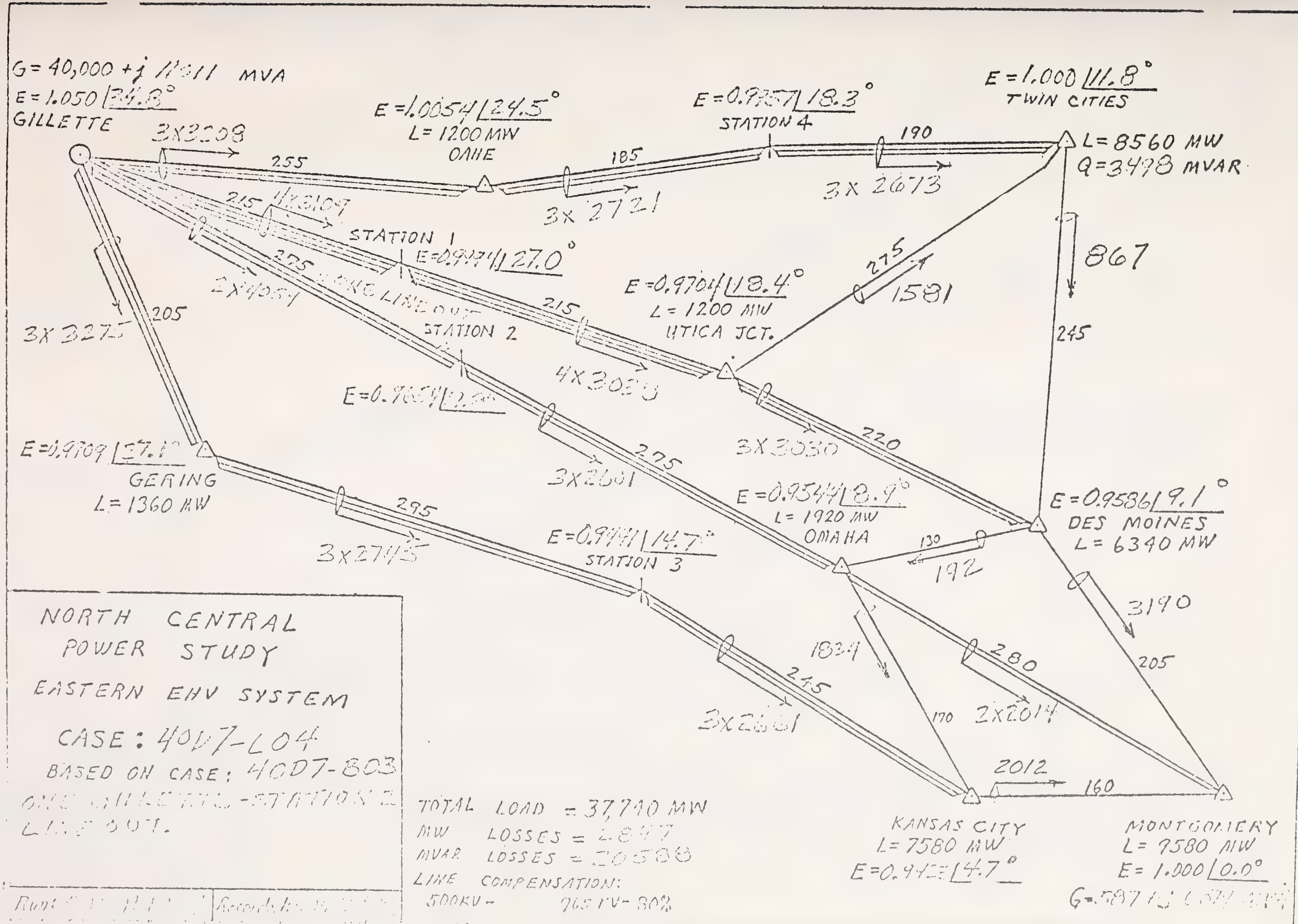

G = 48,000 + j MVA
E = 1.050
GILLETTE
3×3120
255
4×2775
215
275
205
3×3137
E = 1.006 /23.0°
L = 1200 MW
OAHE
185
3×2638
E = 0.977 /17.0°
STATION 4
190
3×2574
E = 1.000 /10.7°
TWIN CITIES
L = 8560 MW
Q = 3253 MVAR
666
245
STATION 1
E = 1.002 /25.5°
215
4×2911
E = 0.975 /17.4°
L = 1200 MW
UTICA JCT.
275
1612
220
3×2858
STATION 2
E = 0.951 /21.3
275
3×3017
E = 0.775 /25.6°
GERING
L = 1360 MW
295
3×2614
E = 0.950 /13.9°
STATION 3
245
3×2537
E = 0.959 /7.4°
L = 1920 MW
OMAHA
130
377
E = 0.963 /8.7°
DES MOINES
L = 6340 MW
3070
205
2151
280
2×2153
170
1974
160
KANSAS CITY
L = 7580 MW
E = 0.947 /4.6°
MONTGOMERY
L = 9580 MW
E = 1.000 /0.0°
G = 444 + j 5730 MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 4007-B03
BASED ON CASE:
GILLETTE - UTICA JCT.
TWIN CITIES - UTICA JCT.
TOTAL LOAD = 37,740 MW
MW LOSSES = 2704
MVAR LOSSES = 19,734
LINE COMPENSATION:
500KV - 765 KV - 80%
Run:
Recorded:

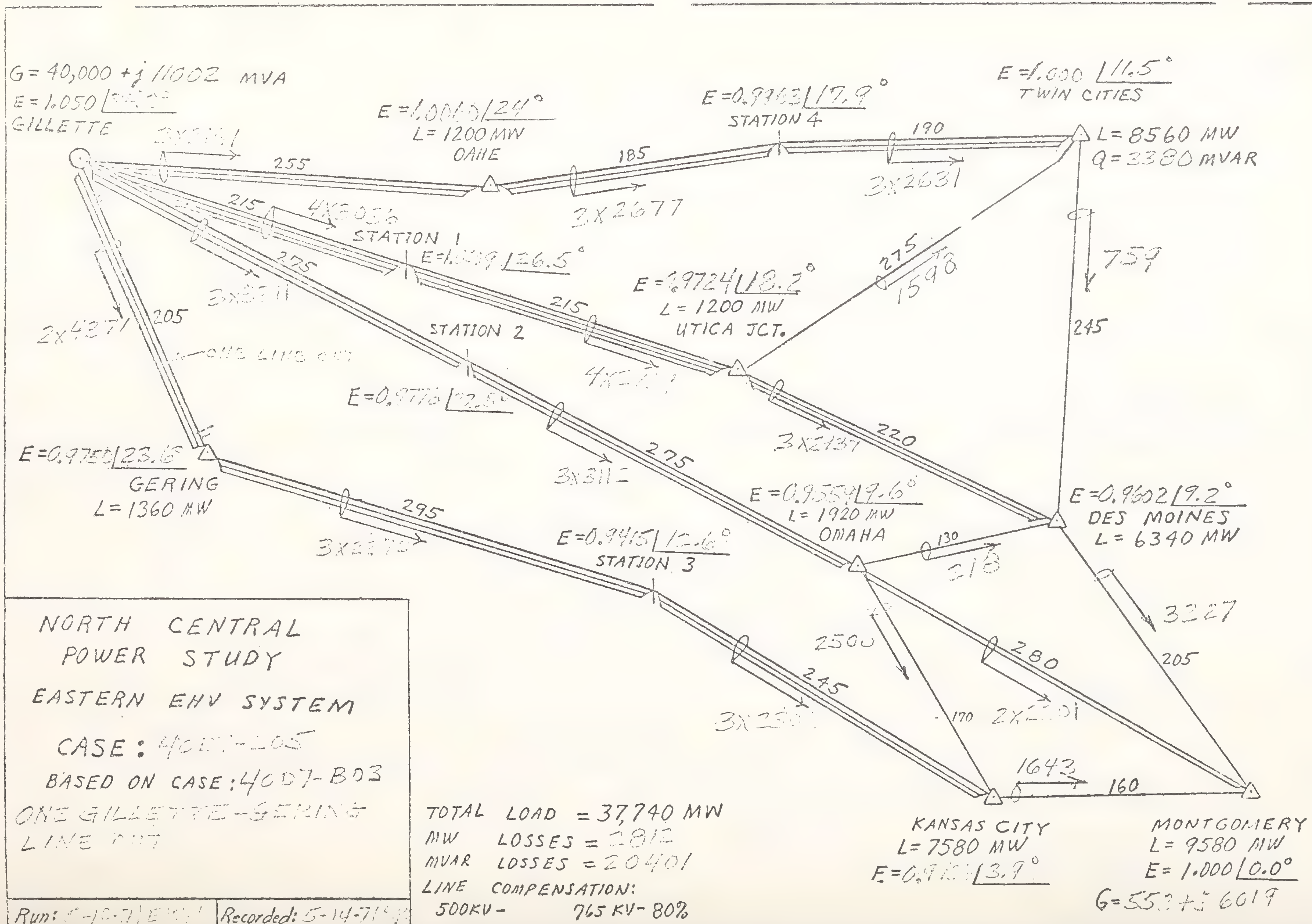


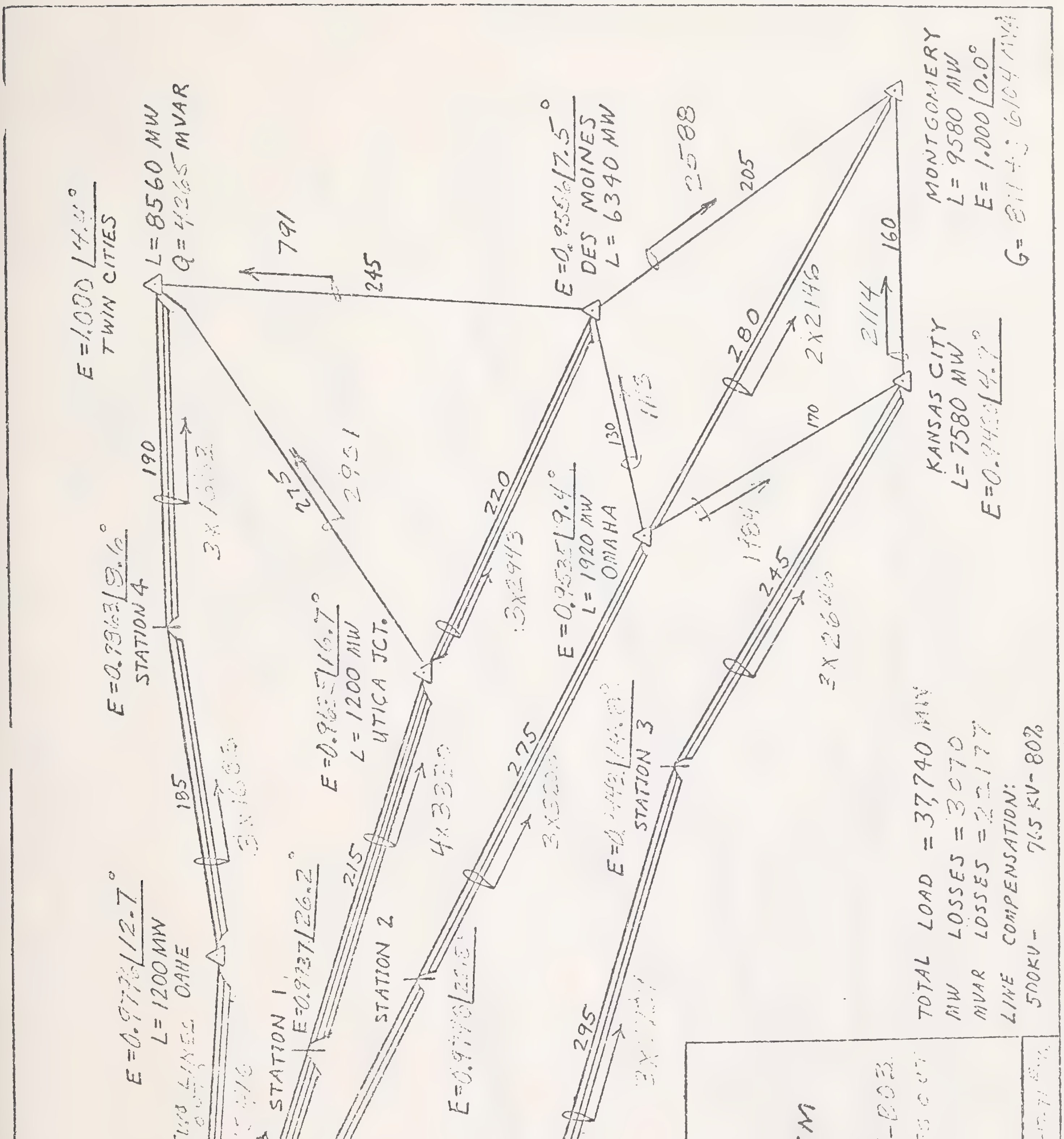
G = 40,000 + j MVA
E = 1.050
GILLETTE
E = 1.006 ⎣24.1°
L = 1200 MW
OAHE
E = 0.976 ⎣18.0°
STATION 4
E = 1.000 ⎣11.6°
TWIN CITIES
L = 8560 MW
Q = 3389 MVAR
255
185
190
3X2674
3X2629
215
4X2771
STATION 1
E = 1.005 ⎣27.2°
275
3X3137
205
3X3216
E = 0.977 ⎣17.7°
L = 1200 MW
UTICA JCT.
1751
1094
245
215
4X2734
STATION 2
E = 0.977
ONE LINE OUT
2X3780
220
E = 0.972 ⎣26.6
GERING
L = 1360 MW
3X3137
275
E = 0.956 ⎣9.5°
L = 1920 MW
OMAHA
E = 0.959 ⎣8.2°
DES MOINES
L = 6340 MW
295
3X2681
E = 0.946 ⎣14.5°
STATION 3
130
777
2843
2064
280
205
245
3X2607
170
2X2175
2087
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 40D7-L01
BASED ON CASE: 4007-803
TOTAL LOAD = 37,740 MW
MW LOSSES = 2773
MVAR LOSSES = 20316
LINE COMPENSATION:
500KV -
765 KV - 80%
KANSAS CITY
L = 7580 MW
E = ⎣4.8°
MONTGOMERY
L = 9580 MW
E = 1.000 ⎣0.0°
G = 533 + j 5117 MVA
Run:
Recorded:

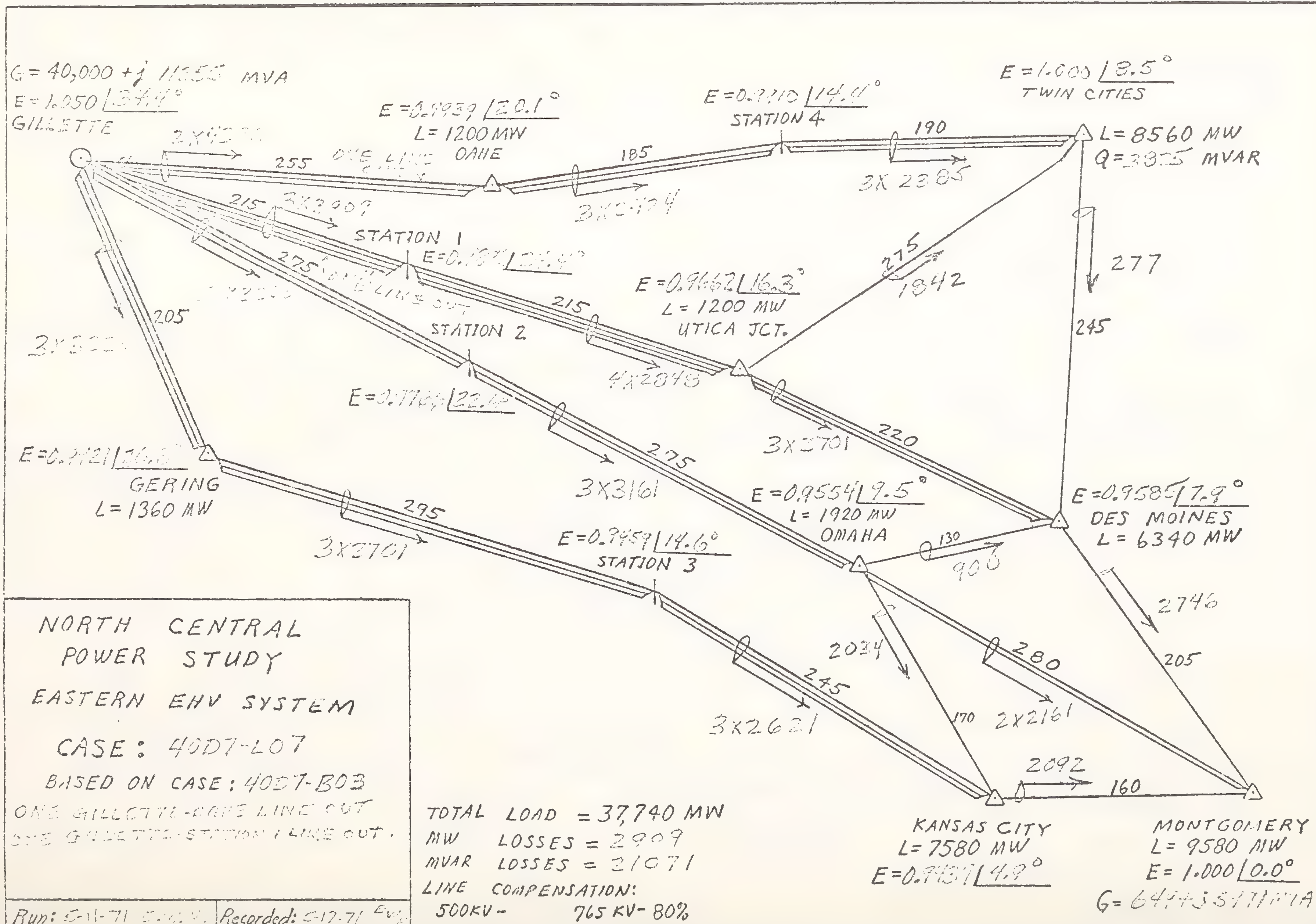

G = 40,000 + j MVA
E = 1.050
GILLETTE
255
215
275
205
E = 1200 MW
OAHE
185
3X2327
E = 0.9124 14.3°
STATION 4
190
3X2273
E = 1.006 18.7°
TWIN CITIES
L = 8560 MW
Q = 3594 MVAR
203
245
STATION 1
3X3174
215
4X3543
E = 0.9716 17.2°
L = 1200 MW
UTIÇA JCT.
275
2041
220
3X2837
STATION 2
3X3175
275
3 X 3078
GERING
L = 1360 MW
295
E = 0.9578 9.4°
L = 1920 MW
OMAHA
130
610
E = 0.9603 13.4°
DES MOINES
L = 6340 MW
2920
205
STATION 3
245
3X2572
2099
170
280
2X2158
2019
160
KANSAS CITY
L = 7580 MW
4.7°
MONTGOMERY
L = 9580 MW
E = 1.000 0.0°
G = 556 + j
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE :
BASED ON CASE :
TOTAL LOAD = 37,740 MW
MW LOSSES = 2816
MVAR LOSSES = 20468
LINE COMPENSATION:
500KV - 765 KV - 80%
Run:
Recorded:


G= 40,000 +j MVA
GILLETTE
E=1.050
255
215
275
205
OAHE
L= 1200 MW
185
3X 2721
STATION 4
190
3X 2673
TWIN CITIES
E=1.000 /11.8°
L=8560 MW
867
245
STATION 1
E=0.9704 /18.4°
L= 1200 MW
UTICA JCT.
275
1581
4X 3030
220
3X 3030
STATION 2
3X 2001
E=0.9586 /9.1°
DES MOINES
L= 6340 MW
130
192
L= 1920 MW
OMAHA
GERING
L= 1360 MW
295
STATION 3
E=0.9441 /14.7
245
3X 2631
1834
170
280
2X 2011
3140
205
2012
160
KANSAS CITY
L= 7580 MW
E=0.945 /4.7°
MONTGOMERY
L= 9580 MW
E= 1.000 /0.0°
TOTAL LOAD = 37,740 MW
MW LOSSES = 2847
MVAR LOSSES = 20588
LINE COMPENSATION:
500KV - 765 KV- 80%
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 40D7-L04
BASED ON CASE: 40D7-803
ONE GILLETTE-STATION 2
LINE OUT
Run:
Recorded:

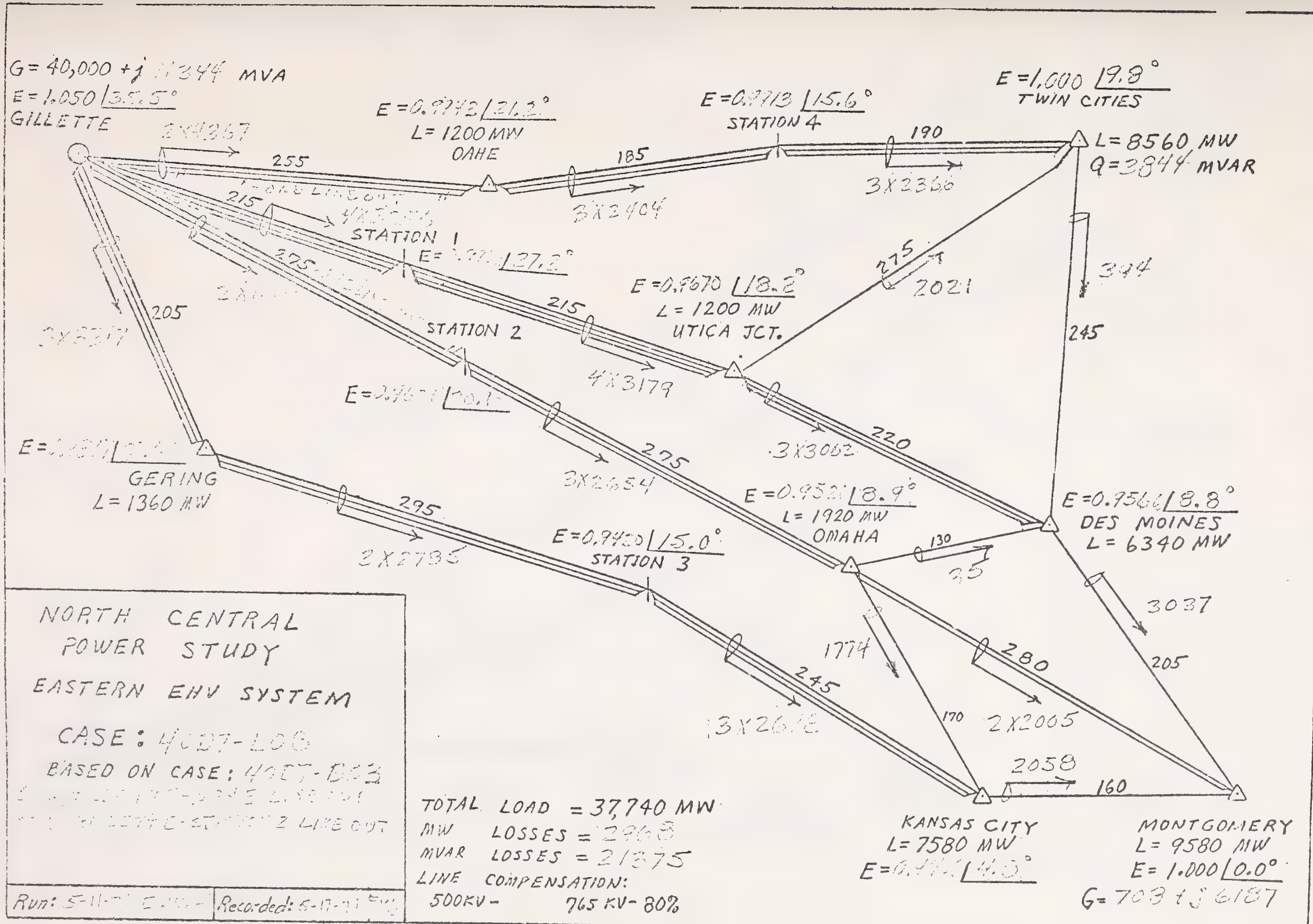

G = 40,000 + j 11011 MVA
E = 1.050 |34.8°
GILLETTE
3X3208
255
215 4X3107
275 2X4057
205
3X 3275
E = 1.0054 |24.5°
L = 1200 MW
OAHE
185
3X 2721
E = 0.9957 |18.3°
STATION 4
190
3X 2673
E = 1.000 |11.8°
TWIN CITIES
L = 8560 MW
Q = 3498 MVAR
867
245
275
1581
STATION 1
E = 0.9974 |27.0°
ONE LINE OUT
STATION 2
E = 0.9704 |18.4°
L = 1200 MW
UTICA JCT.
215
4X3030
3X3030
220
E = 0.9909 |37.1°
GERING
L = 1360 MW
275
3X2601
E = 0.9544 |8.9°
L = 1920 MW
OMAHA
295
3X2745
E = 0.9941 |14.7°
STATION 3
E = 0.9586 |9.1°
DES MOINES
L = 6340 MW
130
192
3190
205
1834
280
2X2014
170
245
3X2601
2012
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 40D7-L04
BASED ON CASE: 40D7-803
TOTAL LOAD = 37,740 MW
MW LOSSES = 2897
MVAR LOSSES = 20588
LINE COMPENSATION:
500KV -
765 KV - 80%
KANSAS CITY
L = 7580 MW
E = 0.9413 |4.7°
MONTGOMERY
L = 9580 MW
E = 1.000 |0.0°


G = 40,000 + j 11002 MVA
E = 1.050
GILLETTE
255
215
275
205
2x4371
E = 1.0060 24°
L = 1200 MW
OAHE
185
3X2677
E = 0.9963 17.9°
STATION 4
190
3x2631
E = 1.000 11.5°
TWIN CITIES
L = 8560 MW
Q = 3380 MVAR
759
245
275
1598
STATION 1
E = 1.0039 26.5°
4X3056
3x3811
215
4X
E = 0.9724 18.2°
L = 1200 MW
UTICA JCT.
STATION 2
E = 0.9776 22.5°
3x3112
275
220
3X2137
E = 0.9602 19.2°
DES MOINES
L = 6340 MW
E = 0.9780 23.6°
GERING
L = 1360 MW
295
3x
E = 0.9415 12.6°
STATION 3
245
3X
E = 0.9559 9.6°
L = 1920 MW
OMAHA
130
218
3227
205
2500
280
170
2X
1643
160
KANSAS CITY
L = 7580 MW
E = 3.9°
MONTGOMERY
L = 9580 MW
E = 1.000 0.0°
G = 553 + j 6019
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE : 40D7-205
BASED ON CASE : 40D7-B03
ONE GILLETTE-GERING
LINE OUT
Run:
Recorded: 5-14-71
TOTAL LOAD = 37,740 MW
MW LOSSES = 2812
MVAR LOSSES = 20401
LINE COMPENSATION:
500KV -
765 KV - 80%

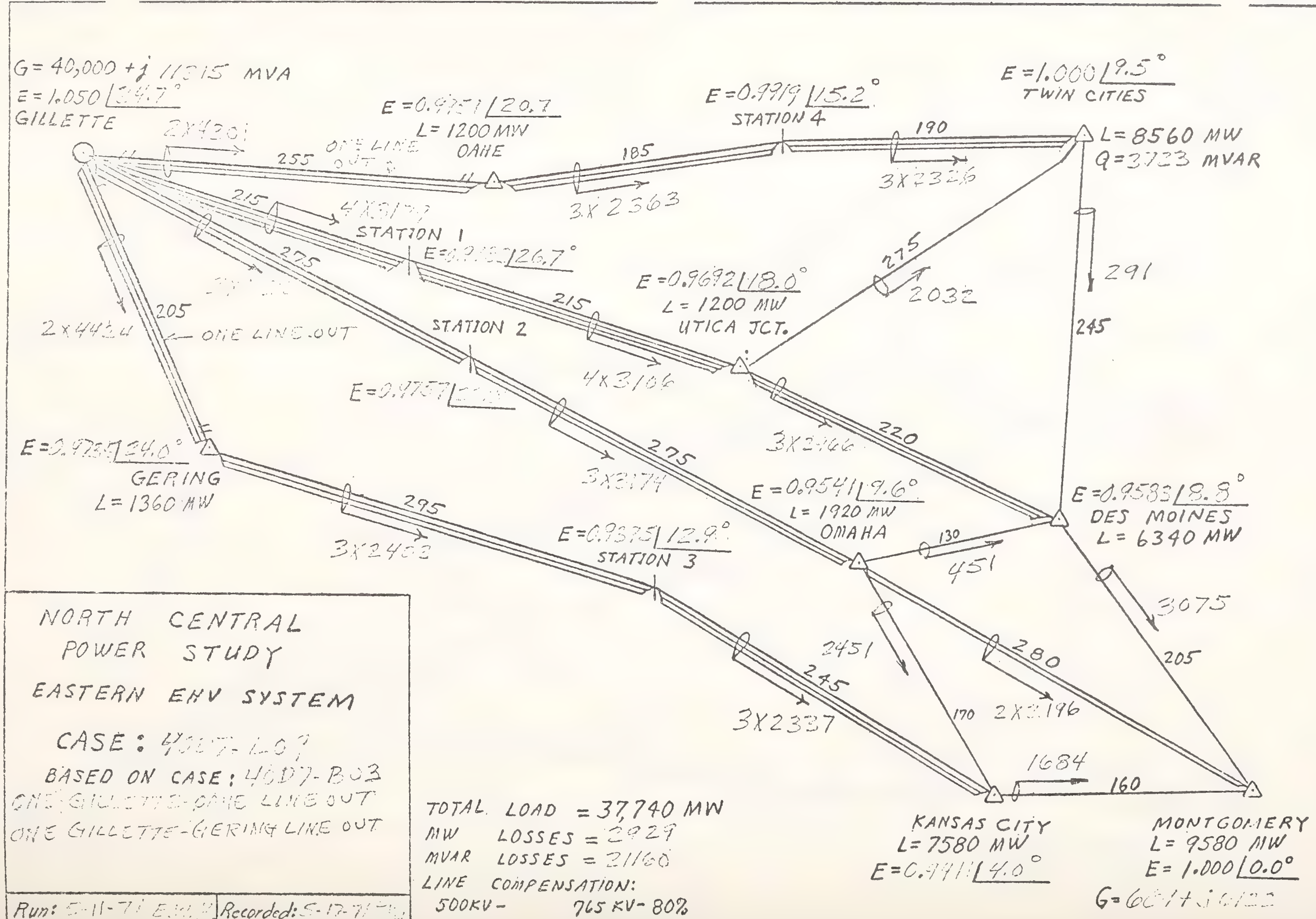

NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE :
BASED ON CASE :
Run:
Recorded:
TOTAL LOAD = 37,740 MW
MW LOSSES = 3070
MVAR LOSSES =
LINE COMPENSATION:
500KV -
765 KV- 80%
GILLETTE
GERING
L = 1360 MW
STATION 1
OAHE
L = 1200 MW
STATION 2
STATION 3
STATION 4
UTICA JCT.
L = 1200 MW
TWIN CITIES
L = 8560 MW
DES MOINES
L = 6340 MW
OMAHA
L = 1920 MW
KANSAS CITY
L = 7580 MW
MONTGOMERY
L = 9580 MW
E = 1.000 | 0.0°

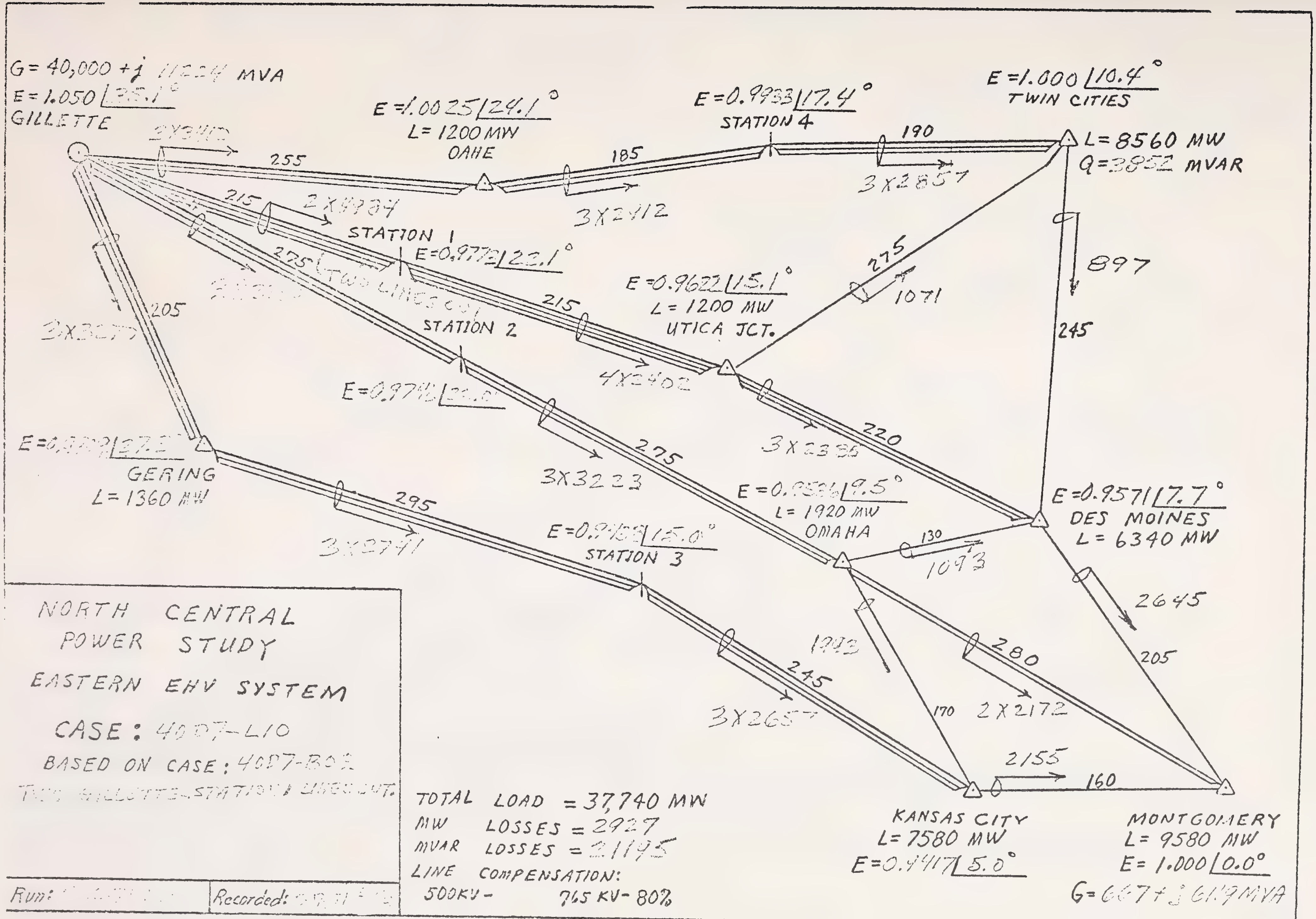


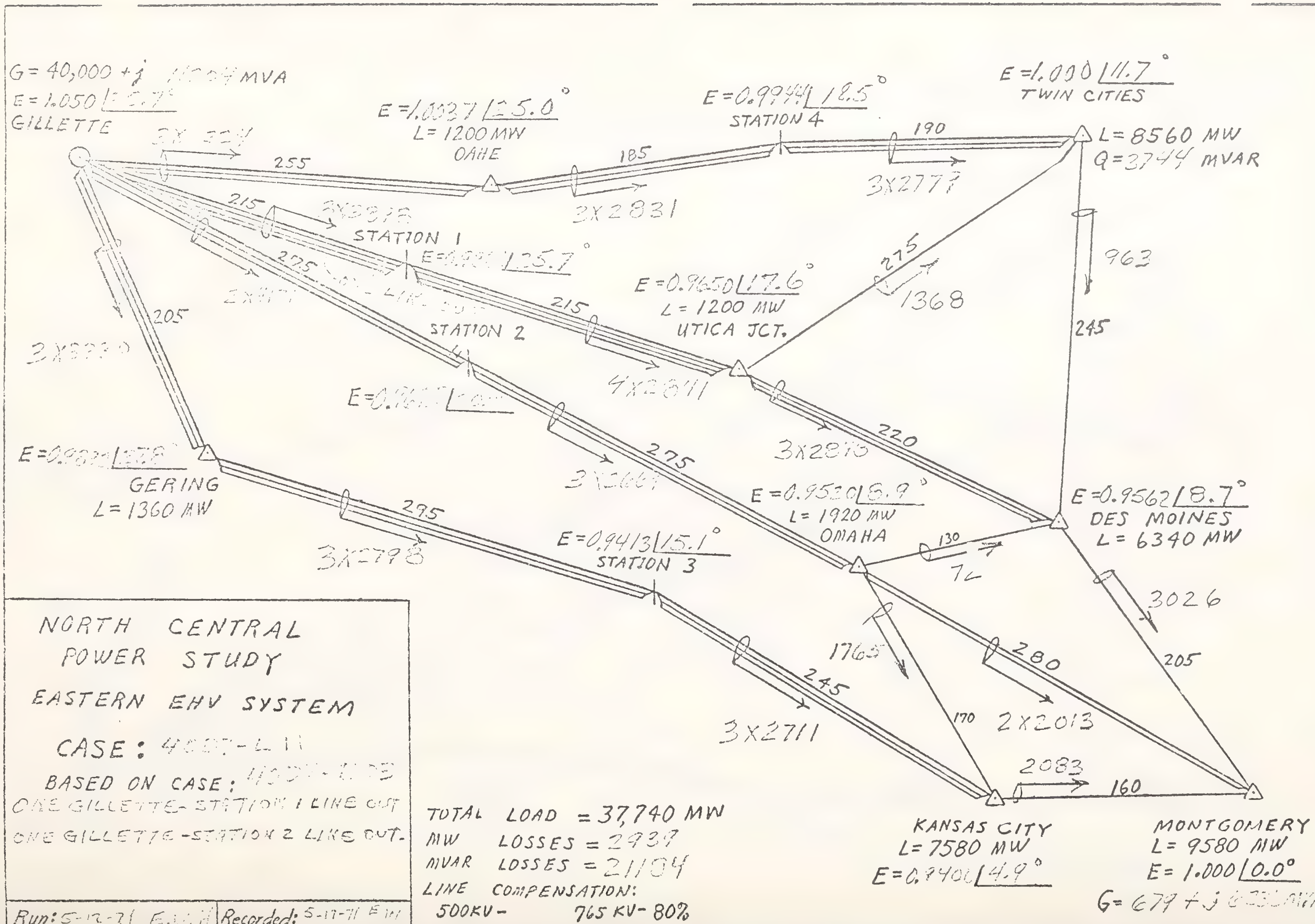
TWIN CITIES
E = 1.000 ∠8.5°
L = 8560 MW
STATION 4
OAHE
L = 1200 MW
E = 0.9939 ∠20.1°
GILLETTE
E = 1.050
G = 40,000 MVA
STATION 1
STATION 2
E = 0.9662 ∠16.3°
L = 1200 MW
UTICA JCT.
GERING
L = 1360 MW
E = 0.9554 ∠9.5°
L = 1920 MW
OMAHA
E = 0.9585 ∠7.9°
DES MOINES
L = 6340 MW
STATION 3
E = 0.9459 ∠14.6°
KANSAS CITY
L = 7580 MW
MONTGOMERY
L = 9580 MW
E = 1.000 ∠0.0°
255
185
190
3X 2385
277
245
215
275
1842
205
4X2848
3X2701
220
275
3X3161
295
3X2701
130
906
2746
205
2034
280
170
2X2161
245
3X2621
2092
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 40D7-L07
BASED ON CASE: 40D7-B03
Run: 5-11-71
Recorded: 5-17-71
TOTAL LOAD = 37,740 MW
MW LOSSES = 2909
MVAR LOSSES = 21071
LINE COMPENSATION:
500KV - 765 KV - 80%

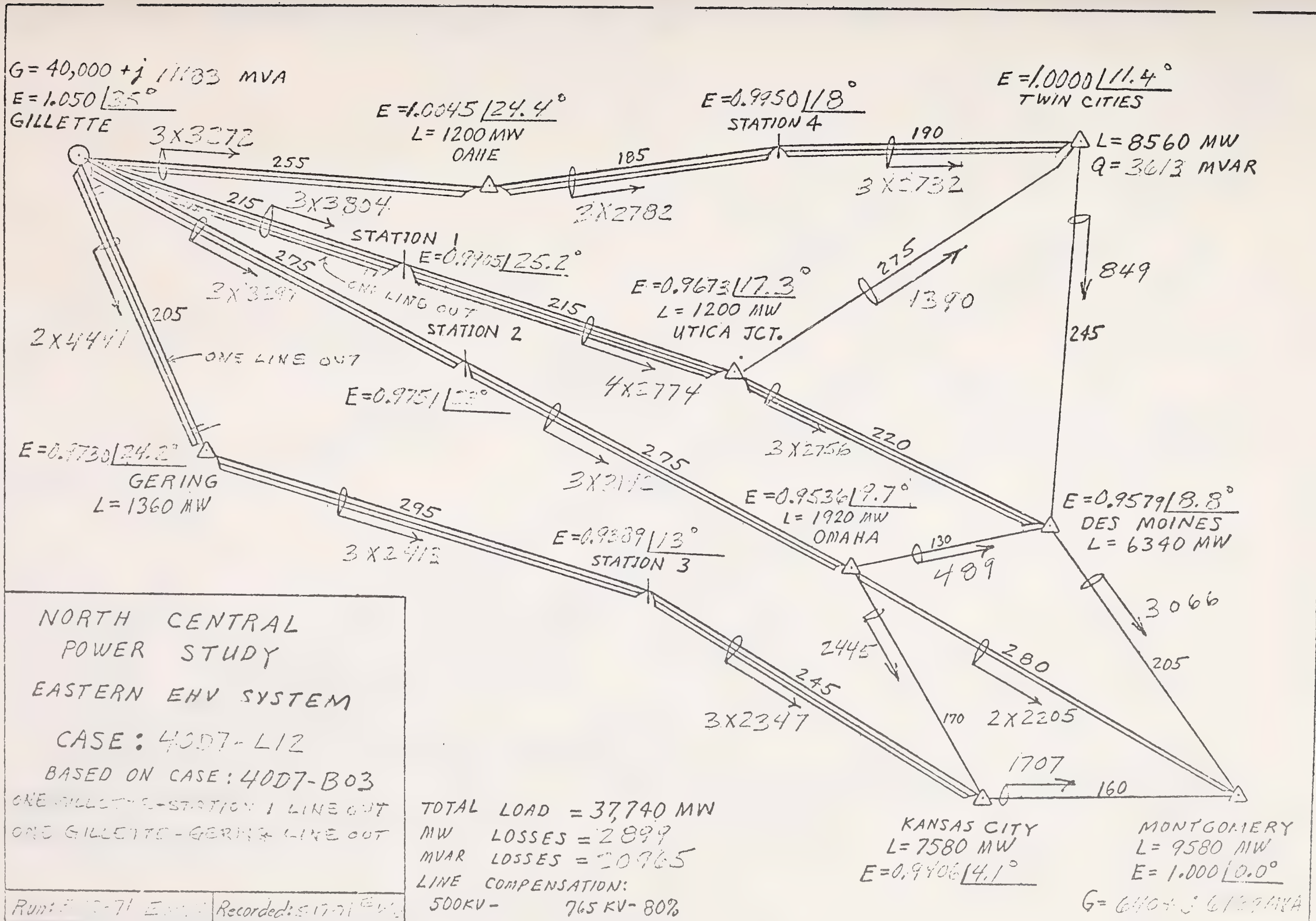


G = 40,000 + j MVA
E = 1.050
GILLETTE
255
215
205
E = 0.9742 /21.2°
L = 1200 MW
OAHE
185
3X2404
E = 0.9713 /15.6°
STATION 4
190
3X2366
E = 1.000 /19.8°
TWIN CITIES
L = 8560 MW
Q = 3844 MVAR
344
245
STATION 1
275
2021
E = 0.9670 /18.2°
L = 1200 MW
UTICA JCT.
4X3179
STATION 2
220
3X3062
3X2654
275
E = 0.9566 /8.8°
DES MOINES
L = 6340 MW
GERING
L = 1360 MW
295
2X2735
E = 0.9420 /15.0°
STATION 3
L = 1920 MW
OMAHA
130
3037
1774
280
205
245
170
2X2005
2058
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE :
BASED ON CASE :
TOTAL LOAD = 37,740 MW
MW LOSSES =
MVAR LOSSES = 21375
LINE COMPENSATION:
500KV -
765 KV - 80%
KANSAS CITY
L = 7580 MW
MONTGOMERY
L = 9580 MW
E = 1.000 /0.0°
Run:
Recorded:

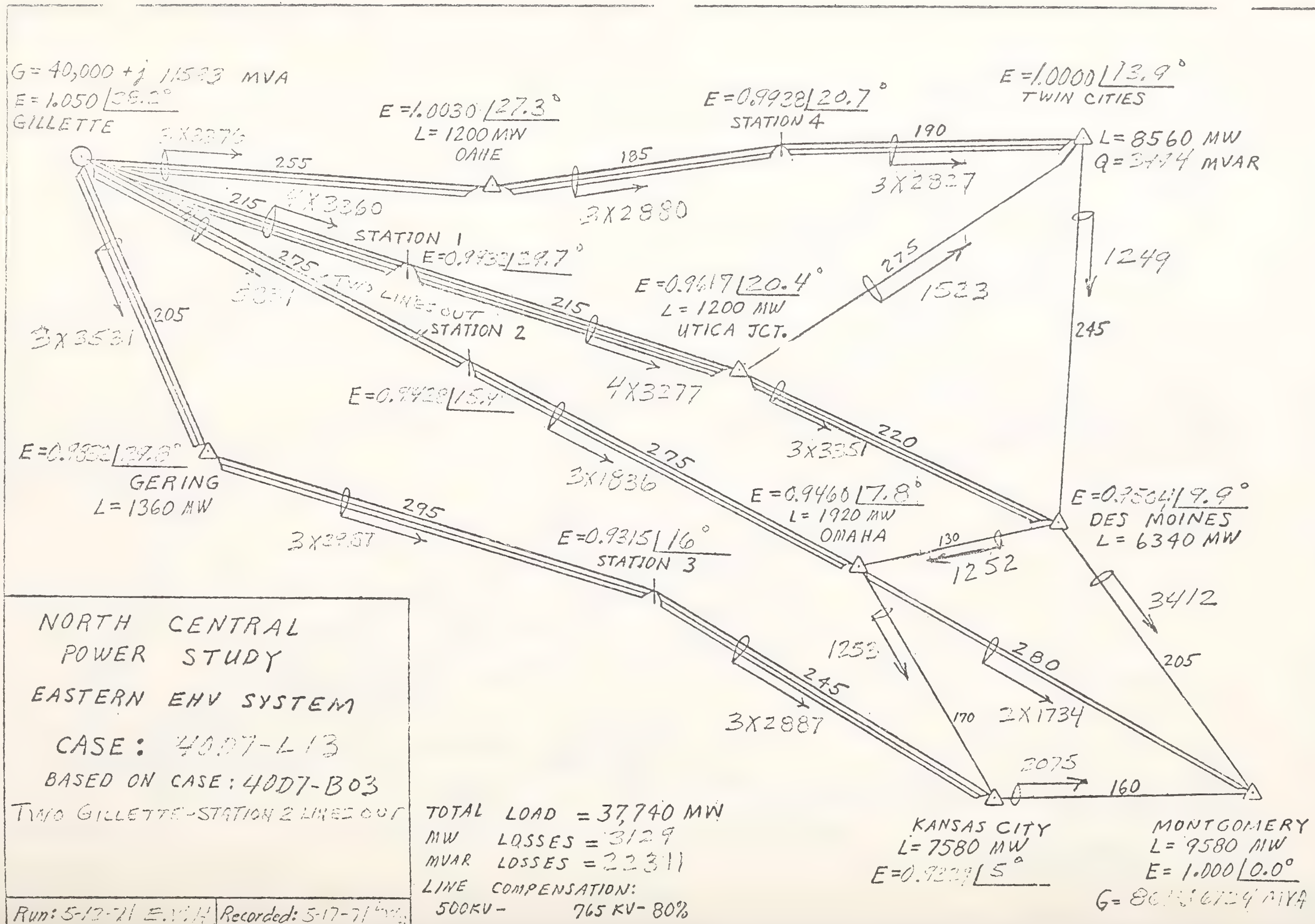

G= 40,000 +j 11515 MVA
E= 1.050 [34.7°
GILLETTE
2X4301
255
ONE LINE OUT
E=0.9751 [20.7
L= 1200 MW
OAHE
185
3X2363
E=0.9919 [15.2°
STATION 4
190
3X2326
E=1.000 [9.5°
TWIN CITIES
L=8560 MW
Q=3723 MVAR
215
4X3177
STATION 1
275
2X4424
205
ONE LINE OUT
STATION 2
215
4X3106
E=0.9692 [18.0°
L= 1200 MW
UTICA JCT.
275
2032
291
245
3X2466
220
275
3X3174
E=0.9541 [9.6°
L= 1920 MW
OMAHA
130
451
E=0.9583 [8.8°
DES MOINES
L= 6340 MW
3075
205
GERING
L= 1360 MW
295
3X2403
STATION 3
245
3X2337
2451
170
280
2X3196
1684
160
NORTH CENTRAL POWER STUDY
EASTERN EHV SYSTEM
CASE:
BASED ON CASE:
ONE GILLETTE-GERING LINE OUT
TOTAL LOAD = 37,740 MW
MW LOSSES = 2929
MVAR LOSSES = 21160
LINE COMPENSATION:
500KV-
765 KV- 80%
KANSAS CITY
L= 7580 MW
MONTGOMERY
L= 9580 MW
E= 1.000 [0.0°
Run:
Recorded:

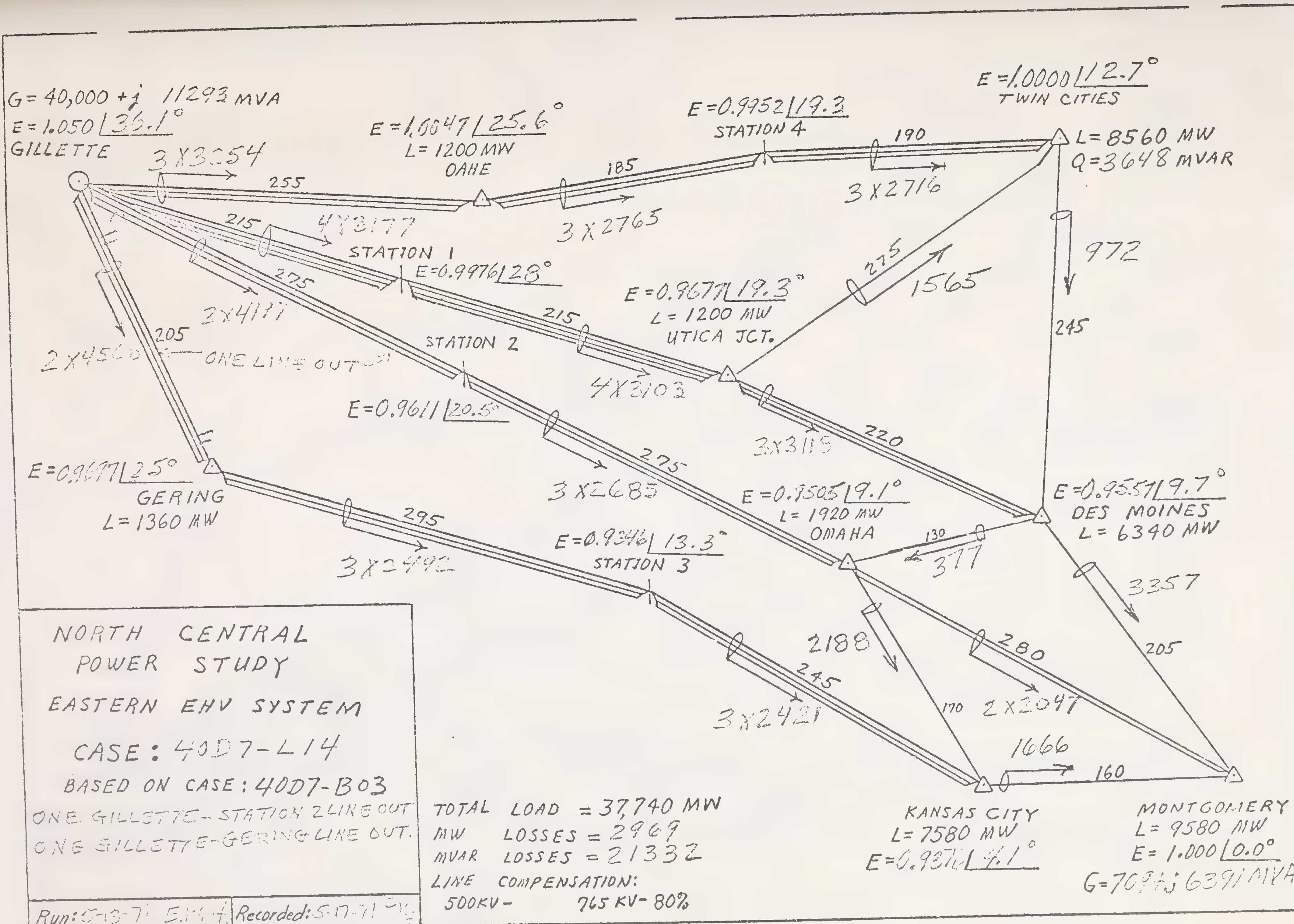

G= 40,000 +j MVA
E= 1.050
GILLETTE
E=1.0025 24.1°
L= 1200 MW
OAHE
E=0.9933 17.4°
STATION 4
E=1.000 10.4°
TWIN CITIES
L=8560 MW
MVAR
255
185
190
3X2857
3X2412
215
STATION 1
E=0.9772 22.1°
275
1071
897
245
E=0.9622 15.1°
L= 1200 MW
UTICA JCT.
215
205
STATION 2
4X2402
220
3X2336
275
3X3223
E=0.9571 7.7°
DES MOINES
L= 6340 MW
E=0.9586 9.5°
L= 1920 MW
OMAHA
130
1093
GERING
L= 1360 MW
295
E=0.9159 15.0°
STATION 3
2645
205
280
245
170
2X2172
2155
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 4007-L10
BASED ON CASE:
TOTAL LOAD = 37,740 MW
MW LOSSES = 2927
MVAR LOSSES =
LINE COMPENSATION:
500KV - 765 KV- 80%
KANSAS CITY
L= 7580 MW
E=0.9417 5.0°
MONTGOMERY
L= 9580 MW
E= 1.000 0.0°
Run:
Recorded:

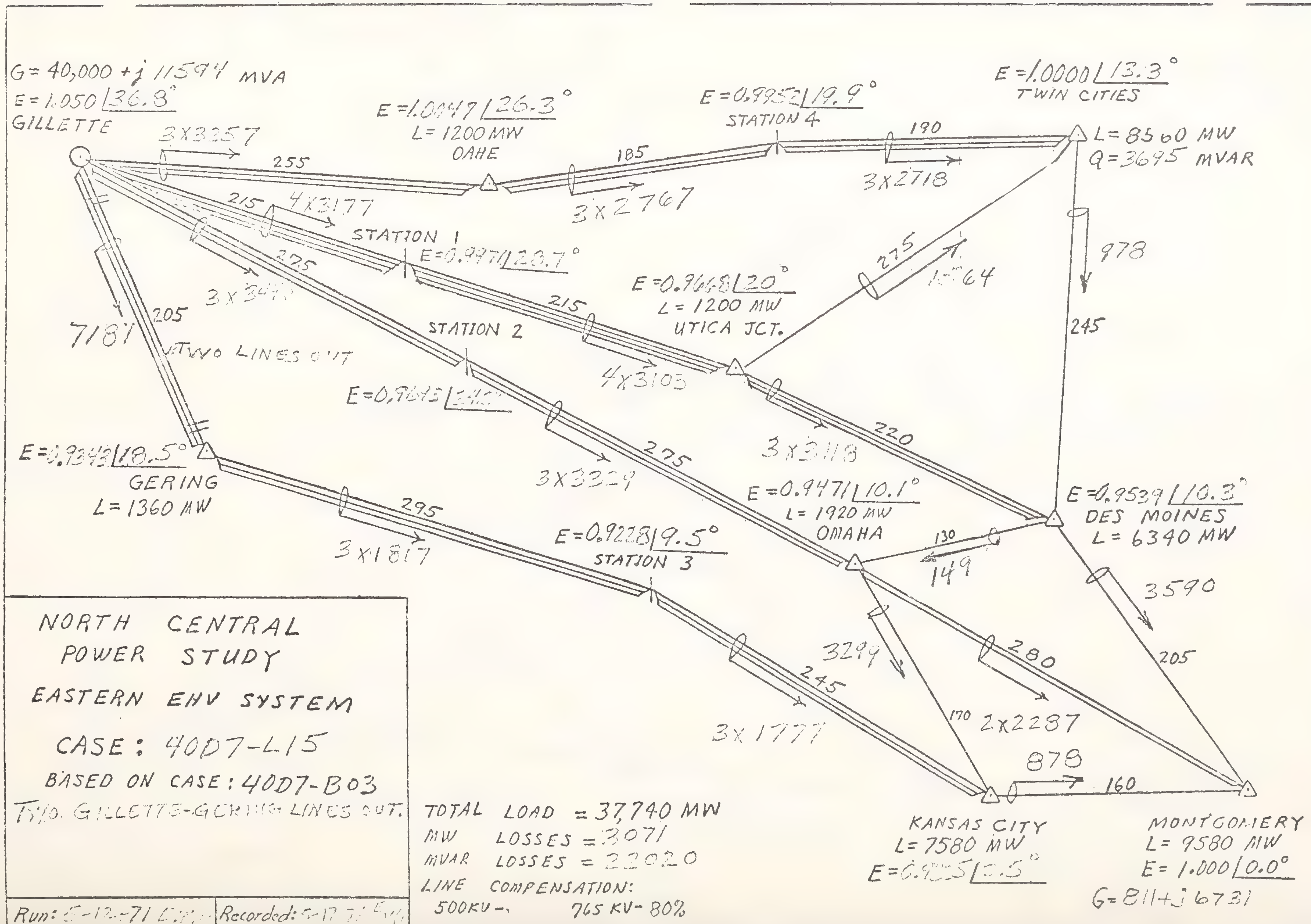

G = 40,000 + j MVA
E = 1.050
GILLETTE
255
205
215
275
E = 1.0037 /5.0°
L = 1200 MW
OAHE
185
3X2831
E = 0.9944 /18.5°
STATION 4
190
3X2777
E = 1.000 /11.7°
TWIN CITIES
L = 8560 MW
Q = 3744 MVAR
963
245
STATION 1
E = /25.7°
215
4X2841
E = 0.9650 /17.6°
L = 1200 MW
UTICA JCT.
275
1368
STATION 2
275
220
3X2815
E = 0.9562 /8.7°
DES MOINES
L = 6340 MW
3X2990
GERING
L = 1360 MW
295
3X2798
E = 0.9413 /15.1°
STATION 3
245
3X2711
E = 0.9530 /8.9°
L = 1920 MW
OMAHA
130
74
1765
170
280
2X2013
3026
205
2083
160
KANSAS CITY
L = 7580 MW
E = 0.9400 /4.9°
MONTGOMERY
L = 9580 MW
E = 1.000 /0.0°
G = 679 + j MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE:
BASED ON CASE:
ONE GILLETTE - STATION 1 LINE OUT
ONE GILLETTE - STATION 2 LINE OUT.
Run: 5-12-71
Recorded: 5-17-71
TOTAL LOAD = 37,740 MW
MW LOSSES = 2939
MVAR LOSSES = 21104
LINE COMPENSATION:
500KV - 765 KV - 80%

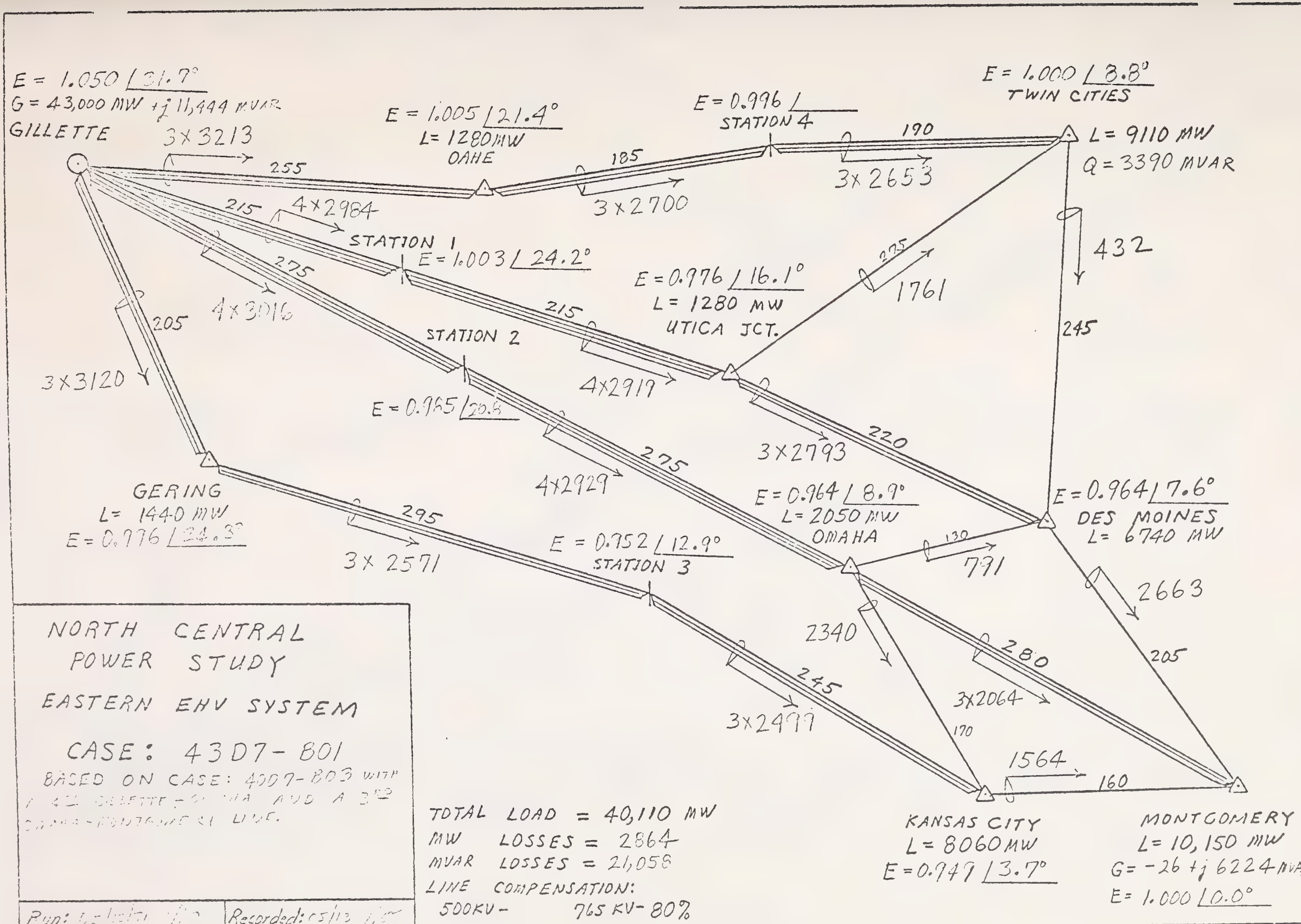


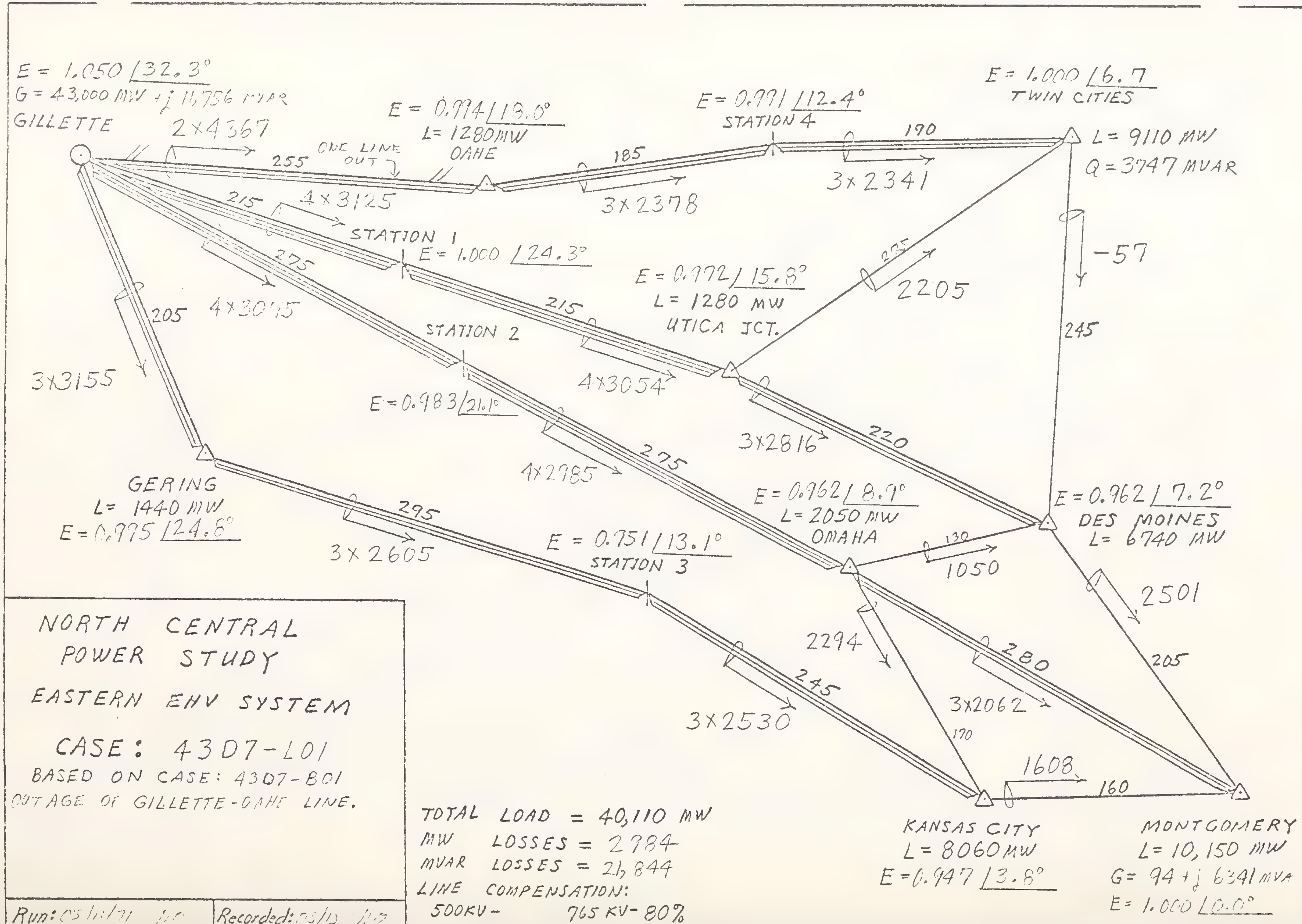
G = 40,000 + j 11183 MVA
E = 1.050
GILLETTE
E = 1.0045 24.4°
L = 1200 MW
OAHE
E = 0.9950 18°
STATION 4
E = 1.0000 11.4°
TWIN CITIES
L = 8560 MW
Q = 3613 MVAR
3X3272
255
185
3X2782
190
3X2732
215
3X3804
STATION 1
E = 0.9905 25.2°
275
ONE LINE OUT
E = 0.9673 17.3°
L = 1200 MW
UTICA JCT.
275
1390
849
245
2X4441
205
ONE LINE OUT
STATION 2
215
4X2774
E = 0.9751
E = 0.9730 24.2°
GERING
L = 1360 MW
3X2756
220
275
E = 0.9536 9.7°
L = 1920 MW
OMAHA
E = 0.9579 8.8°
DES MOINES
L = 6340 MW
295
3X2412
E = 0.9389 13°
STATION 3
130
489
3066
2445
280
205
245
3X2347
170
2X2205
1707
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 40D7-L12
BASED ON CASE: 40D7-B03
ONE GILLETTE-GERING LINE OUT
TOTAL LOAD = 37,740 MW
MW LOSSES = 2899
MVAR LOSSES = 20965
LINE COMPENSATION:
500KV - 765 KV - 80%
KANSAS CITY
L = 7580 MW
E = 0.9406 4.1°
MONTGOMERY
L = 9580 MW
E = 1.000 0.0°
Run:
Recorded:


G= 40,000 + j
MVA
E= 1.050
GILLETTE
E = 1.0030 |27.3°
L= 1200 MW
OAHE
E=0.9938 |20.7°
STATION 4
E = 1.0000 |13.9°
TWIN CITIES
L= 8560 MW
Q= MVAR
255
185
190
3X2880
3X2827
215
4X3360
STATION 1
E=0.99
275
TWO LINES OUT
STATION 2
205
3X3531
E=0.9617 |20.4°
L = 1200 MW
UTICA JCT.
275
1523
1249
245
215
4X3277
E=0.9920
220
3X3351
275
3X1836
E=0.9460 |7.8°
L= 1920 MW
OMAHA
E=0.9504 |9.9°
DES MOINES
L = 6340 MW
GERING
L= 1360 MW
295
E=0.9315 |16°
STATION 3
130
1252
3412
1253
280
205
245
3X2887
170
2X1734
2075
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 4007-L13
BASED ON CASE: 4007-B03
TWO GILLETTE-STATION 2 LINES OUT
TOTAL LOAD = 37,740 MW
MW LOSSES = 3129
MVAR LOSSES = 22311
LINE COMPENSATION:
500KV -
765 KV- 80%
KANSAS CITY
L= 7580 MW
E=0.9239 |5°
MONTGOMERY
L= 9580 MW
E= 1.000 |0.0°
G=
MVA
Run: 5-12-71
Recorded: 5-17-71

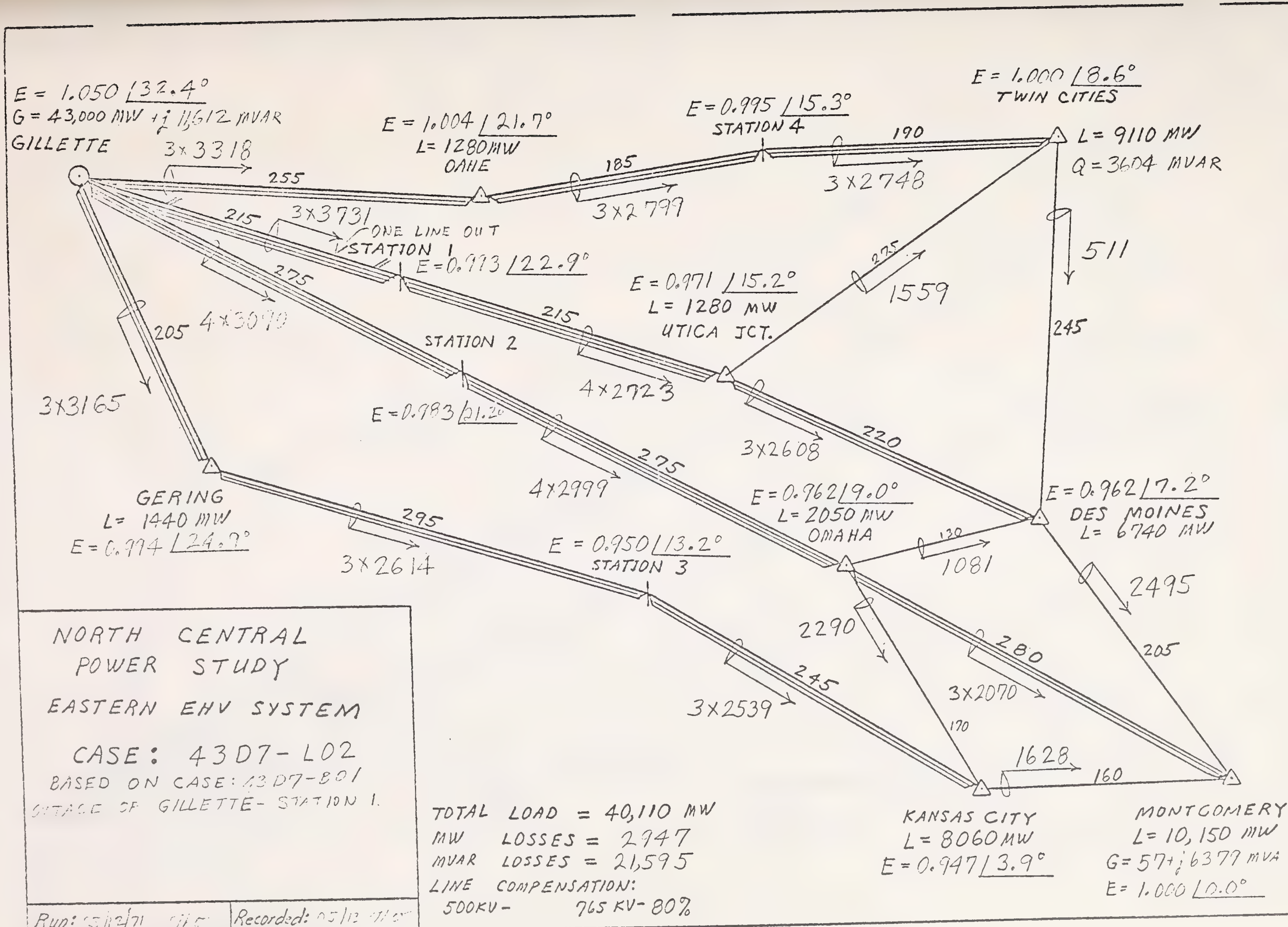

G= 40,000 +j 11293 MVA
E= 1.050 ∠36.1°
GILLETTE
3X3254
255
E = 1.0047 ∠25.6°
L= 1200 MW
OAHE
185
3 X 2765
E = 0.9952 ∠19.3
STATION 4
190
3 X 2716
E = 1.0000 ∠12.7°
TWIN CITIES
L= 8560 MW
Q= 3648 MVAR
972
245
215
4X3177
STATION 1
E= 0.9976 ∠28°
275
2X4111
205
2X4560
ONE LINE OUT
STATION 2
E= 0.9611 ∠20.5°
215
4X3103
E = 0.9677 ∠19.3°
L = 1200 MW
UTICA JCT.
275
1565
3X3119
220
275
3 X2685
E= 0.9697 ∠25°
GERING
L= 1360 MW
295
3X2492
E= 0.9346 ∠13.3°
STATION 3
E = 0.9505 ∠9.1°
L= 1920 MW
OMAHA
130
377
E = 0.9557 ∠9.7°
DES MOINES
L = 6340 MW
3357
205
2188
245
3X2421
280
170
2X2047
1666
160
KANSAS CITY
L= 7580 MW
E= 0.9376 ∠4.1°
MONTGOMERY
L= 9580 MW
E= 1.000 ∠0.0°
G= 7094j 6391 MVA
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 40D7-L14
BASED ON CASE: 40D7-B03
ONE GILLETTE-STATION 2 LINE OUT
ONE GILLETTE-GERING LINE OUT.
Run: 5-13-71 E.M.H.
Recorded: 5-17-71
TOTAL LOAD = 37,740 MW
MW LOSSES = 2969
MVAR LOSSES = 21332
LINE COMPENSATION:
500KV-
765 KV- 80%

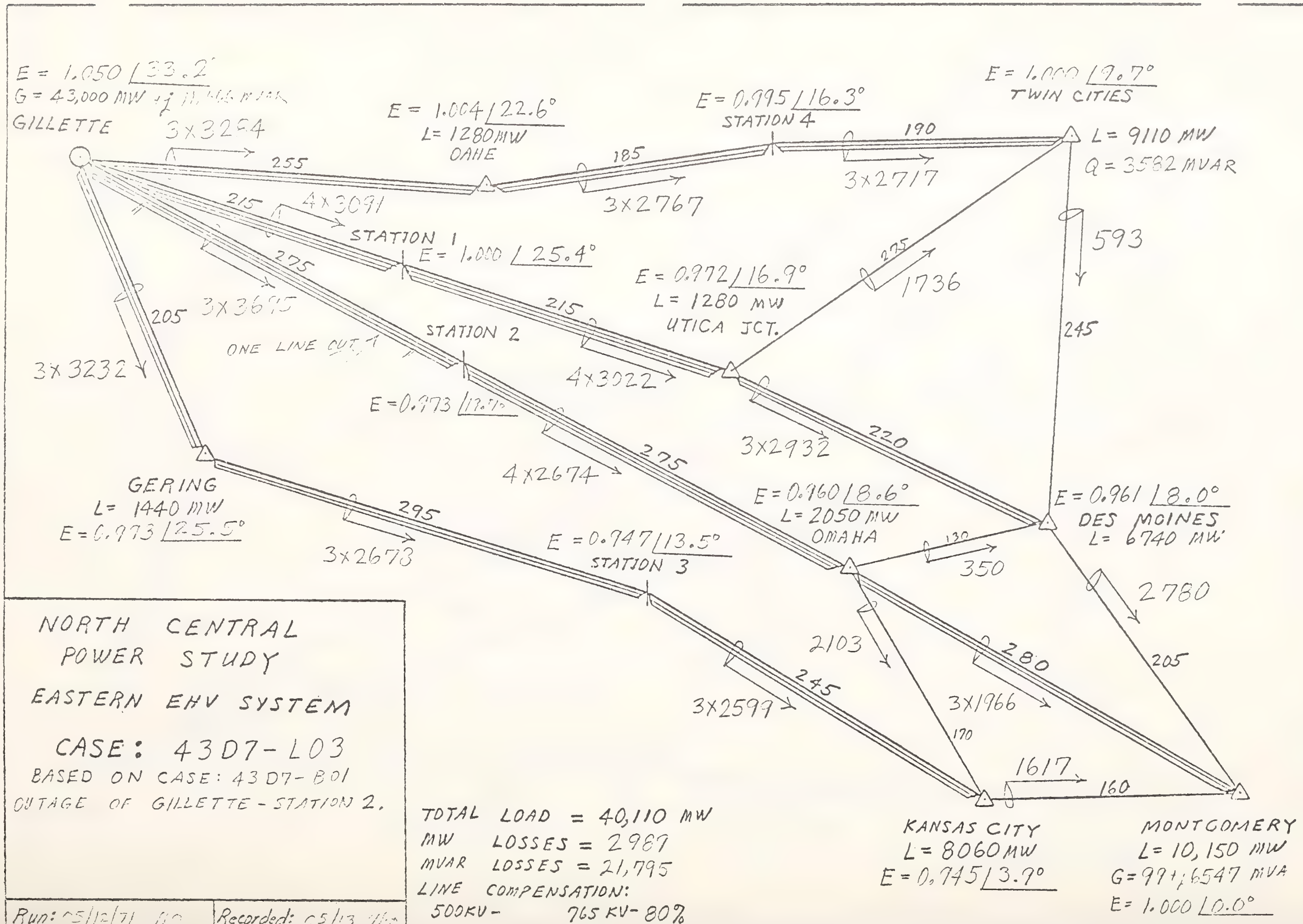

G = 40,000 + j 11594 MVA
E = 1.050 ∠36.8°
GILLETTE
3X3257
255
E = 1.0047 ∠26.3°
L = 1200 MW
OAHE
185
3X2767
E = 0.9952 ∠19.9°
STATION 4
190
3X2718
E = 1.0000 ∠13.3°
TWIN CITIES
L = 8560 MW
Q = 3695 MVAR
978
245
215
4X3177
STATION 1
275
3X3443
205
7181
TWO LINES OUT
STATION 2
215
E = 0.9668 ∠20°
L = 1200 MW
UTICA JCT.
4X3105
275
220
3X3118
3X3329
275
E = 0.9343 ∠18.5°
GERING
L = 1360 MW
295
3X1817
E = 0.9228 ∠9.5°
STATION 3
E = 0.9471 ∠10.1°
L = 1920 MW
OMAHA
130
149
E = 0.9539 ∠10.3°
DES MOINES
L = 6340 MW
3590
205
3299
280
245
3X1777
170
2X2287
878
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 40D7-L15
BASED ON CASE: 40D7-B03
TWO GILLETTE-GERING LINES OUT.
TOTAL LOAD = 37,740 MW
MW LOSSES = 3071
MVAR LOSSES = 22020
LINE COMPENSATION:
500KV -
765 KV - 80%
KANSAS CITY
L = 7580 MW
MONTGOMERY
L = 9580 MW
E = 1.000 ∠0.0°
G = 811 + j 6731
Run: 5-12-71
Recorded:


E = 1.050 ∠31.7°
G = 43,000 MW + j 11,444 MVAR
GILLETTE
3×3213
255
E = 1.005 ∠21.4°
L= 1280 MW
OAHE
185
3×2700
E = 0.996 ∠
STATION 4
190
3×2653
E = 1.000 ∠3.8°
TWIN CITIES
L = 9110 MW
Q = 3390 MVAR
432
245
215
4×2984
STATION 1
E = 1.003 ∠24.2°
275
4×3016
205
3×3120
STATION 2
E = 0.965 ∠20.8
215
4×2917
E = 0.976 ∠16.1°
L = 1280 MW
UTICA JCT.
275
1761
220
3×2793
275
4×2929
E = 0.964 ∠8.9°
L = 2050 MW
OMAHA
130
791
E = 0.964 ∠7.6°
DES MOINES
L = 6740 MW
2663
205
GERING
L= 1440 MW
E = 0.976 ∠24.3°
295
3×2571
E = 0.952 ∠12.9°
STATION 3
245
3×2499
2340
170
280
3×2064
1564
160
KANSAS CITY
L = 8060 MW
E = 0.949 ∠3.7°
MONTGOMERY
L = 10,150 MW
G = -26 + j 6224 MVA
E = 1.000 ∠0.0°
TOTAL LOAD = 40,110 MW
MW LOSSES = 2864
MVAR LOSSES = 21,058
LINE COMPENSATION:
500KV - 765 KV - 80%
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-801
BASED ON CASE: 4007-803 WITH
Run:
Recorded:

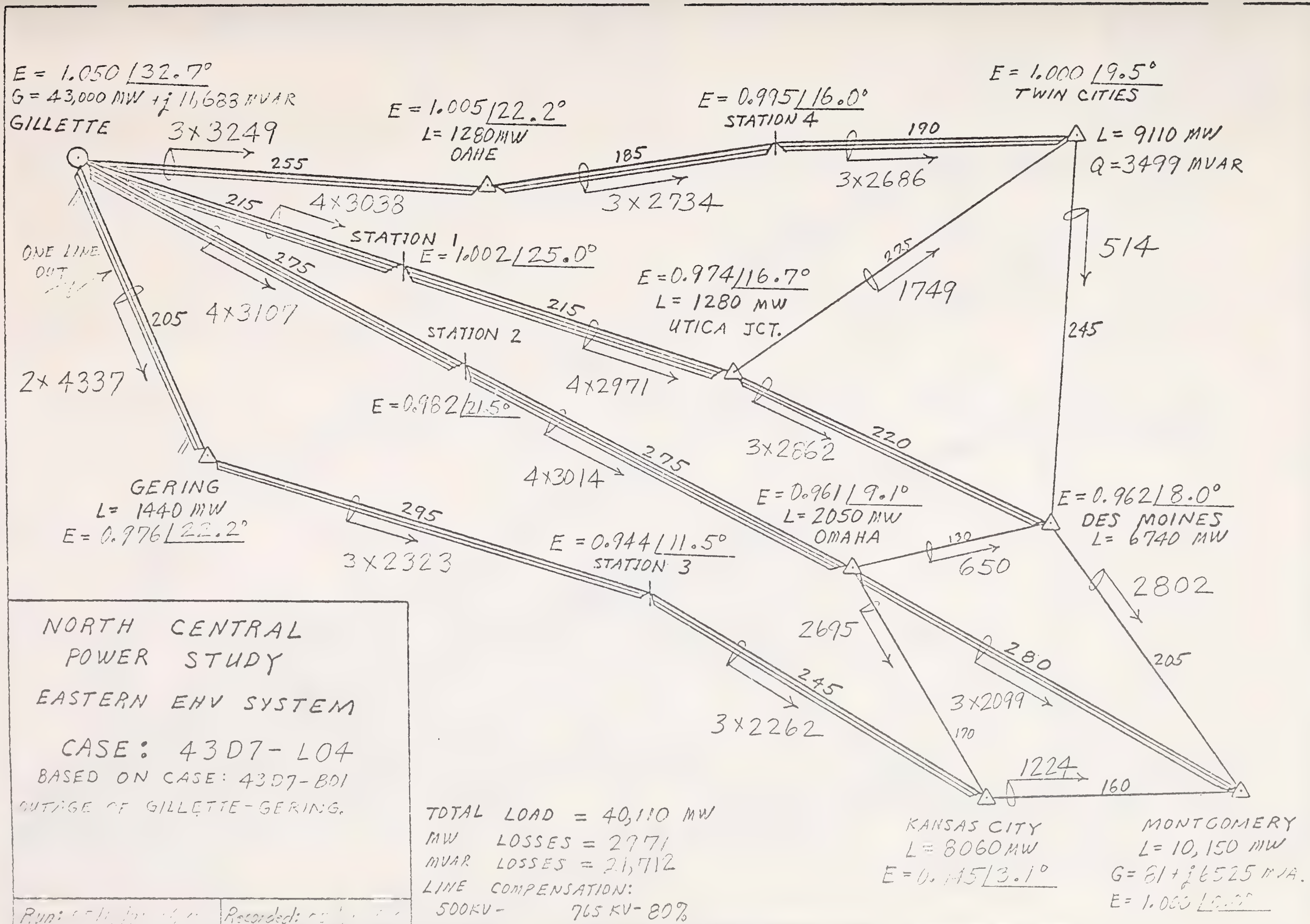


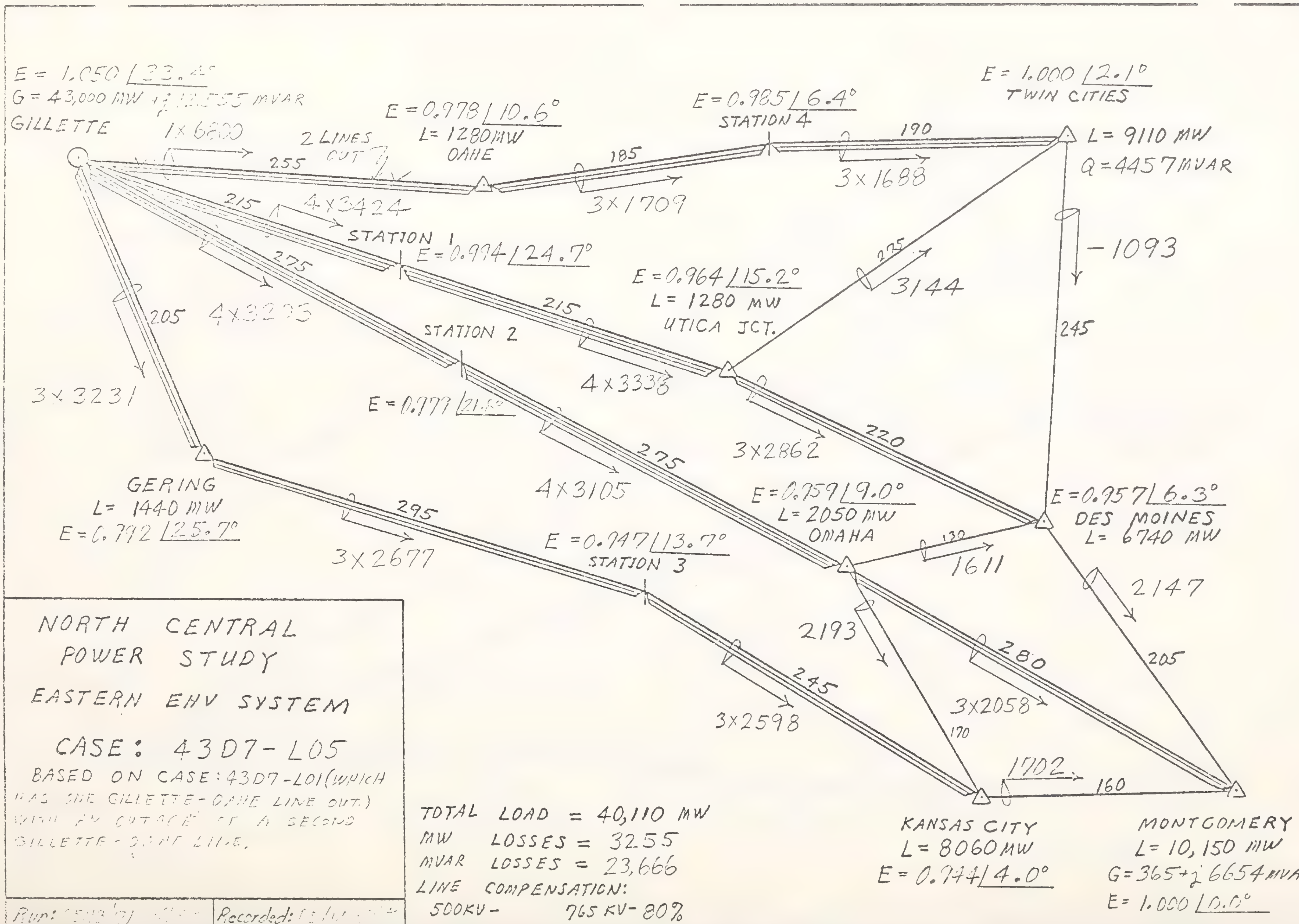
E = 1.050 /32.3°
G = 43,000 MW + j 11,756 MVAR
GILLETTE
2×4367
255
ONE LINE OUT
E = 0.994 /13.0°
L = 1280 MW
OAHE
185
3×2378
E = 0.991 /12.4°
STATION 4
190
3×2341
E = 1.000 /6.7
TWIN CITIES
L = 9110 MW
Q = 3747 MVAR
215
4×3125
STATION 1
E = 1.000 /24.3°
275
4×3015
205
3×3155
STATION 2
E = 0.983 /21.1°
215
4×3054
E = 0.972 /15.8°
L = 1280 MW
UTICA JCT.
275
2205
-57
245
3×2816
220
4×2985
275
E = 0.962 /8.9°
L = 2050 MW
OMAHA
130
1050
E = 0.962 /7.2°
DES MOINES
L = 6740 MW
2501
205
GERING
L = 1440 MW
E = 0.995 /24.6°
295
3×2605
E = 0.951 /13.1°
STATION 3
245
3×2530
2294
170
280
3×2062
1608
160
KANSAS CITY
L = 8060 MW
E = 0.947 /3.8°
MONTGOMERY
L = 10,150 MW
G = 94 + j 6341 MVA
E = 1.000 /0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L01
BASED ON CASE: 43D7-B01
OUTAGE OF GILLETTE-OAHE LINE.
TOTAL LOAD = 40,110 MW
MW LOSSES = 2984
MVAR LOSSES = 21,844
LINE COMPENSATION:
500KV - 765 KV - 80%
Run:
Recorded:

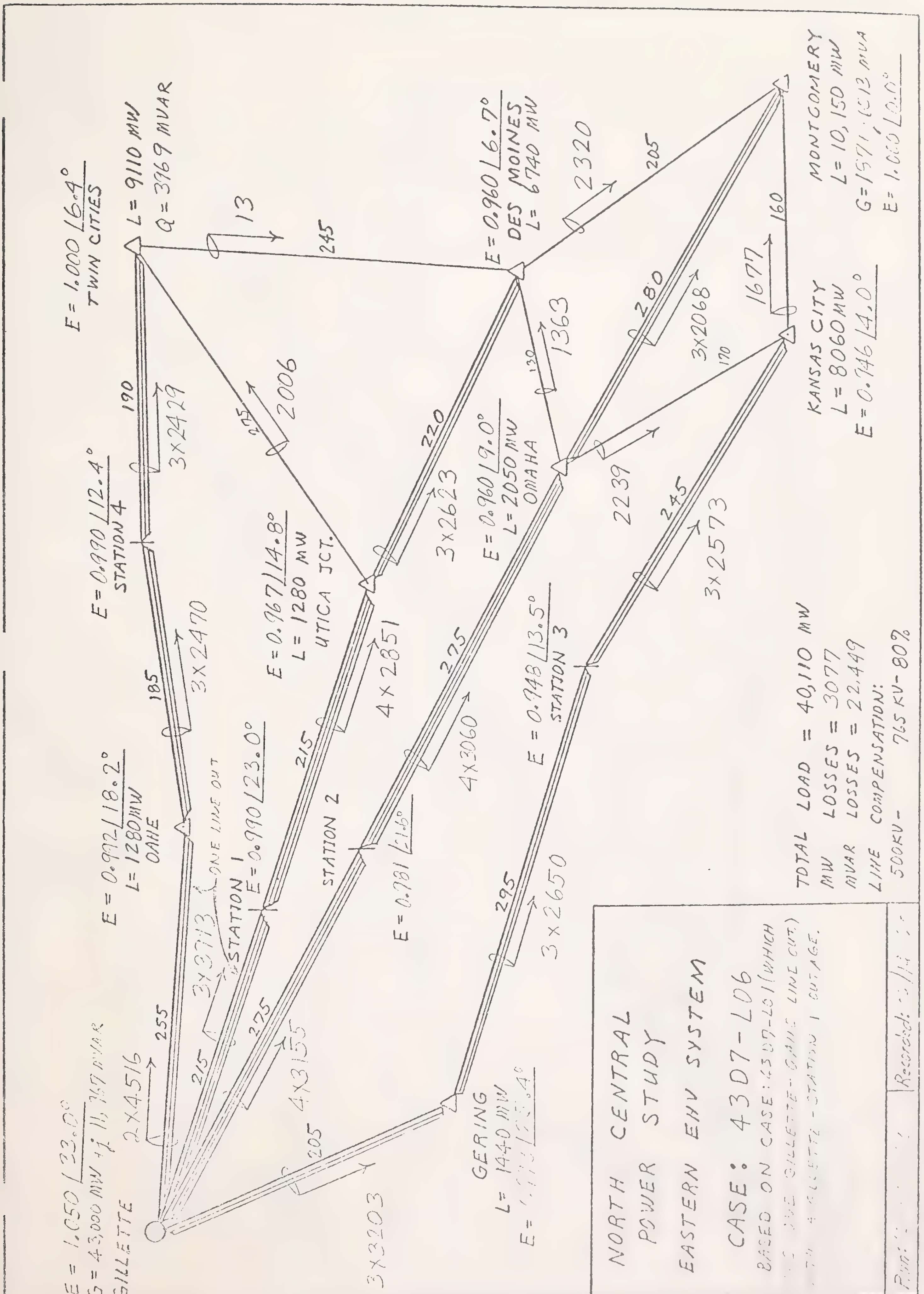

E = 1.050 ∠32.4°
G = 43,000 MW + j 11,612 MVAR
GILLETTE
3×3318
255
E = 1.004 ∠21.7°
L = 1280 MW
OAHE
185
3×2799
E = 0.995 ∠15.3°
STATION 4
190
3×2748
E = 1.000 ∠8.6°
TWIN CITIES
L = 9110 MW
Q = 3604 MVAR
511
245
215
3×3731
ONE LINE OUT
STATION 1
E = 0.993 ∠22.9°
275
4×3070
205
3×3165
275
1559
E = 0.971 ∠15.2°
L = 1280 MW
UTICA JCT.
215
4×2723
STATION 2
E = 0.983 ∠21.2°
4×2999
275
220
3×2608
GERING
L = 1440 MW
E = 0.974 ∠24.9°
295
3×2614
E = 0.950 ∠13.2°
STATION 3
245
3×2539
E = 0.962 ∠9.0°
L = 2050 MW
OMAHA
130
1081
E = 0.962 ∠7.2°
DES MOINES
L = 6740 MW
2495
205
2290
280
3×2070
170
1628
160
KANSAS CITY
L = 8060 MW
E = 0.947 ∠3.9°
MONTGOMERY
L = 10,150 MW
G = 57 + j 6377 MVA
E = 1.000 ∠0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L02
BASED ON CASE: 43D7-801
OUTAGE OF GILLETTE - STATION 1.
TOTAL LOAD = 40,110 MW
MW LOSSES = 2947
MVAR LOSSES = 21,595
LINE COMPENSATION:
500KV -
765 KV - 80%
Run:
Recorded:



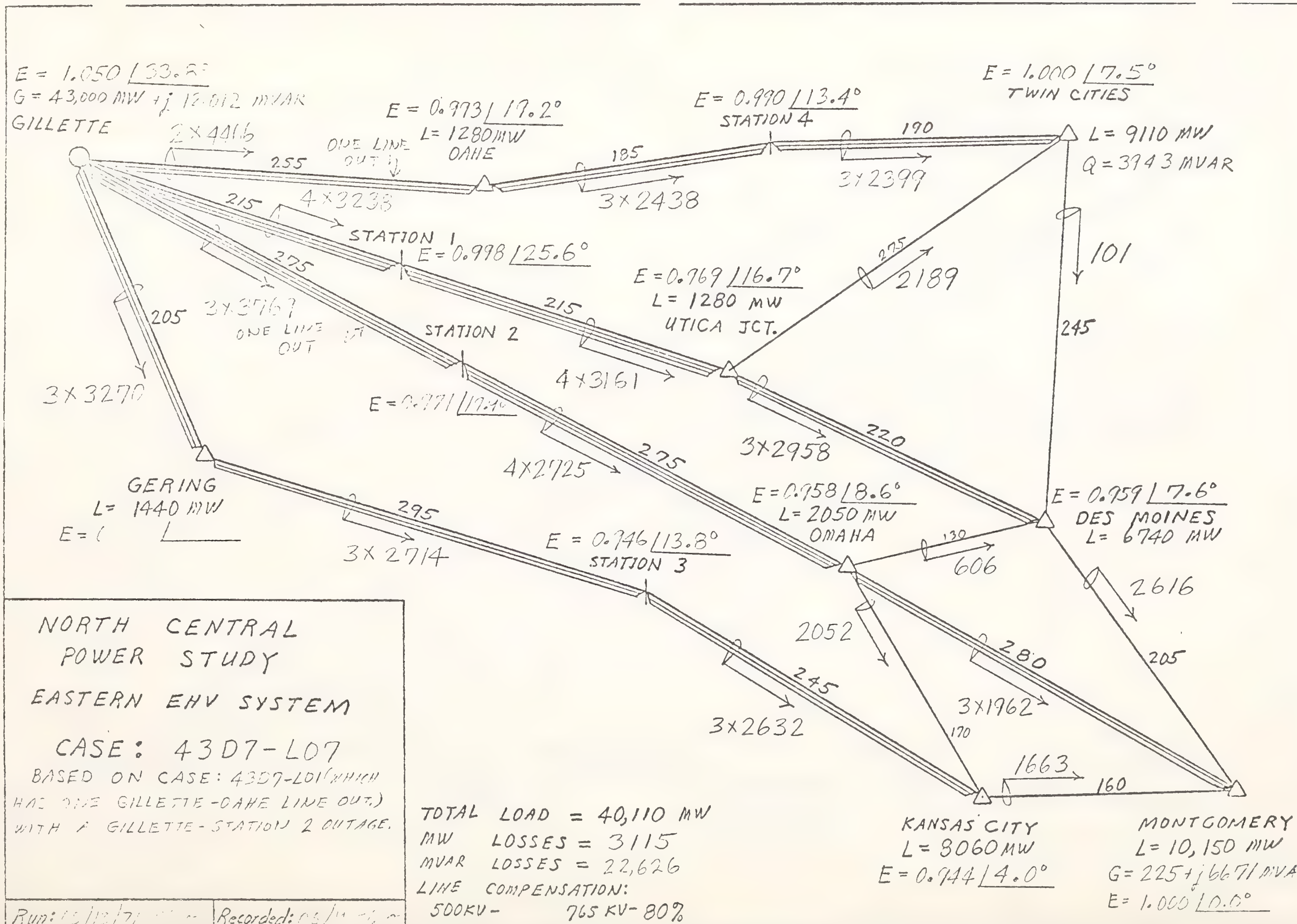
E = 1.050 /33.2°
G = 43,000 MW
GILLETTE
3x3254
255
E = 1.004 /22.6°
L = 1280 MW
OAHE
185
3x2767
E = 0.995 /16.3°
STATION 4
190
3x2717
E = 1.000 /19.7°
TWIN CITIES
L = 9110 MW
Q = 3582 MVAR
593
245
215
4x3091
STATION 1
E = 1.000 /25.4°
275
1736
E = 0.972 /16.9°
L = 1280 MW
UTICA JCT.
215
4x3022
3x2932
220
275
3x3695
205
3x3232
ONE LINE OUT
STATION 2
E = 0.973
275
4x2674
GERING
L = 1440 MW
E = 0.973 /25.5°
295
3x2673
E = 0.947 /13.5°
STATION 3
245
3x2599
E = 0.960 /8.6°
L = 2050 MW
OMAHA
130
350
E = 0.961 /8.0°
DES MOINES
L = 6740 MW
2780
205
2103
170
280
3x1966
1617
160
KANSAS CITY
L = 8060 MW
E = 0.745 /3.9°
MONTGOMERY
L = 10,150 MW
G = 99 + j6547 MVA
E = 1.000 /0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L03
BASED ON CASE: 43D7-B01
OUTAGE OF GILLETTE - STATION 2.
TOTAL LOAD = 40,110 MW
MW LOSSES = 2987
MVAR LOSSES = 21,795
LINE COMPENSATION:
500KV - 765 KV - 80%
Run:
Recorded:


E = 1.050 ∠32.7°
G = 43,000 MW + j 16,683 MVAR
GILLETTE
3×3249
255
E = 1.005 ∠22.2°
L = 1280 MW
OAHE
185
3 × 2734
E = 0.995 ∠16.0°
STATION 4
190
3×2686
E = 1.000 ∠19.5°
TWIN CITIES
L = 9110 MW
Q = 3499 MVAR
215
4×3038
STATION 1
E = 1.002 ∠25.0°
ONE LINE OUT
205
4×3107
275
2× 4337
STATION 2
E = 0.982 ∠21.5°
215
4×2971
E = 0.974 ∠16.7°
L = 1280 MW
UTICA JCT.
275
1749
514
245
3×2662
220
4×3014
275
GERING
L = 1440 MW
E = 0.976 ∠22.2°
295
3×2323
E = 0.944 ∠11.5°
STATION 3
E = 0.961 ∠9.1°
L = 2050 MW
OMAHA
130
650
E = 0.962 ∠8.0°
DES MOINES
L = 6740 MW
2802
2695
280
205
245
3×2262
3×2099
170
1224
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L04
BASED ON CASE: 43D7-B01
OUTAGE OF GILLETTE-GERING.
TOTAL LOAD = 40,110 MW
MW LOSSES = 2771
MVAR LOSSES = 21,712
LINE COMPENSATION:
500KV - 765 KV-80%
KANSAS CITY
L = 8060 MW
MONTGOMERY
L = 10,150 MW
G = 61 + j 6525 MVA.
Run:
Recorded:

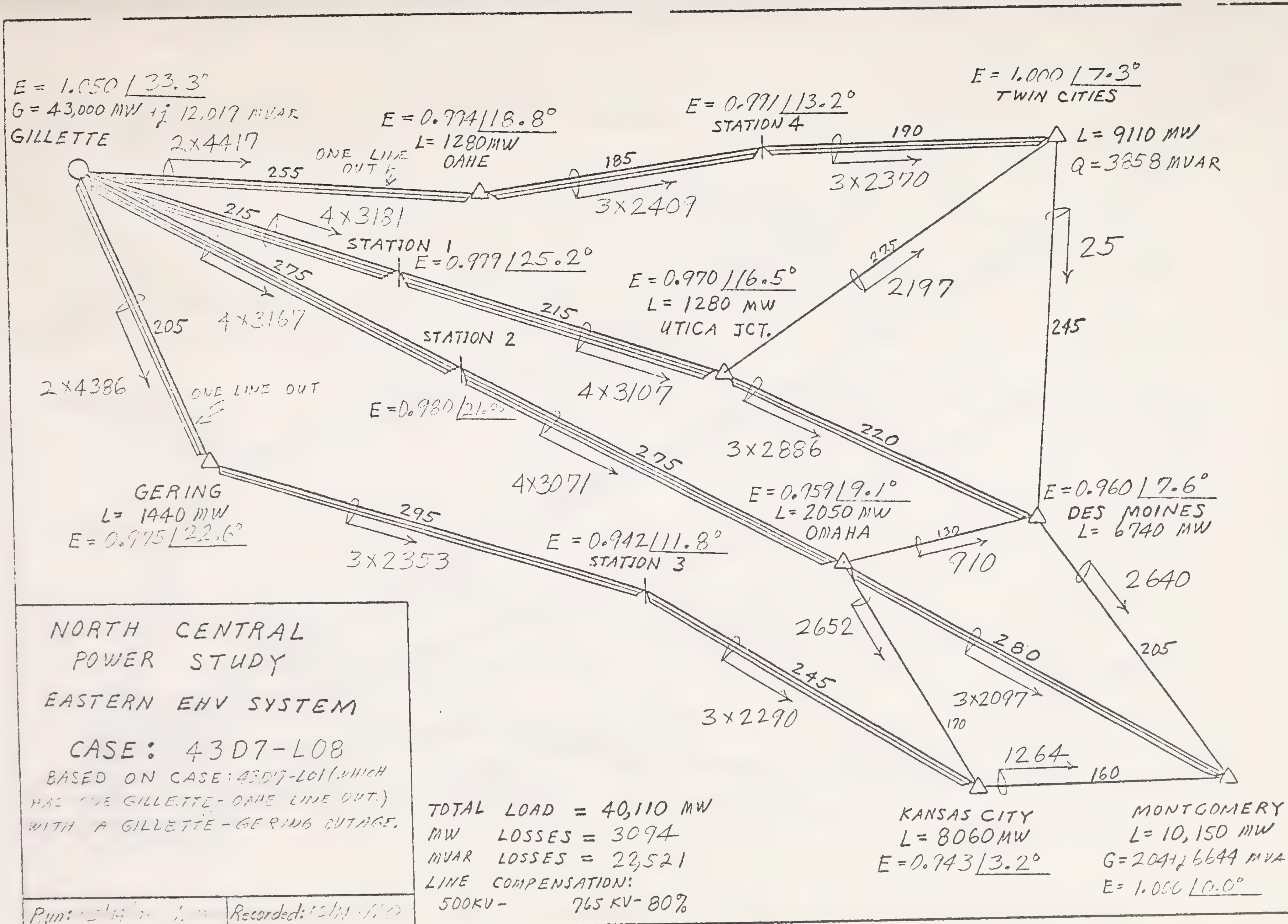

E = 1.050 ∠33.4°
GILLETTE
1X 6800
2 LINES OUT
255
E = 0.978 ∠10.6°
L = 1280 MW
OAHE
185
3X1709
E = 0.985 ∠6.4°
STATION 4
190
3X1688
E = 1.000 ∠2.1°
TWIN CITIES
L = 9110 MW
Q = 4457 MVAR
-1093
245
215
4X3424
STATION 1
E = 0.994 ∠24.7°
275
205
3X3231
STATION 2
E = 0.977
215
E = 0.964 ∠15.2°
L = 1280 MW
UTICA JCT.
275
3144
4X3338
220
3X2862
275
4X3105
GERING
L = 1440 MW
E = 0.992 ∠25.7°
295
3X2677
E = 0.947 ∠13.7°
STATION 3
E = 0.959 ∠9.0°
L = 2050 MW
OMAHA
130
1611
E = 0.957 ∠6.3°
DES MOINES
L = 6740 MW
2147
205
2193
170
245
3X2598
280
3X2058
1702
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L05
BASED ON CASE: 43D7-L01 (WHICH HAS ONE GILLETTE-OAHE LINE OUT.) WITH AN OUTAGE OF A SECOND GILLETTE-OAHE LINE.
TOTAL LOAD = 40,110 MW
MW LOSSES = 3255
MVAR LOSSES = 23,666
LINE COMPENSATION:
500KV - 765KV - 80%
KANSAS CITY
L = 8060 MW
E = 0.944 ∠4.0°
MONTGOMERY
L = 10,150 MW
G = 365 + j 6654 MVA.
E = 1.000 ∠0.0°

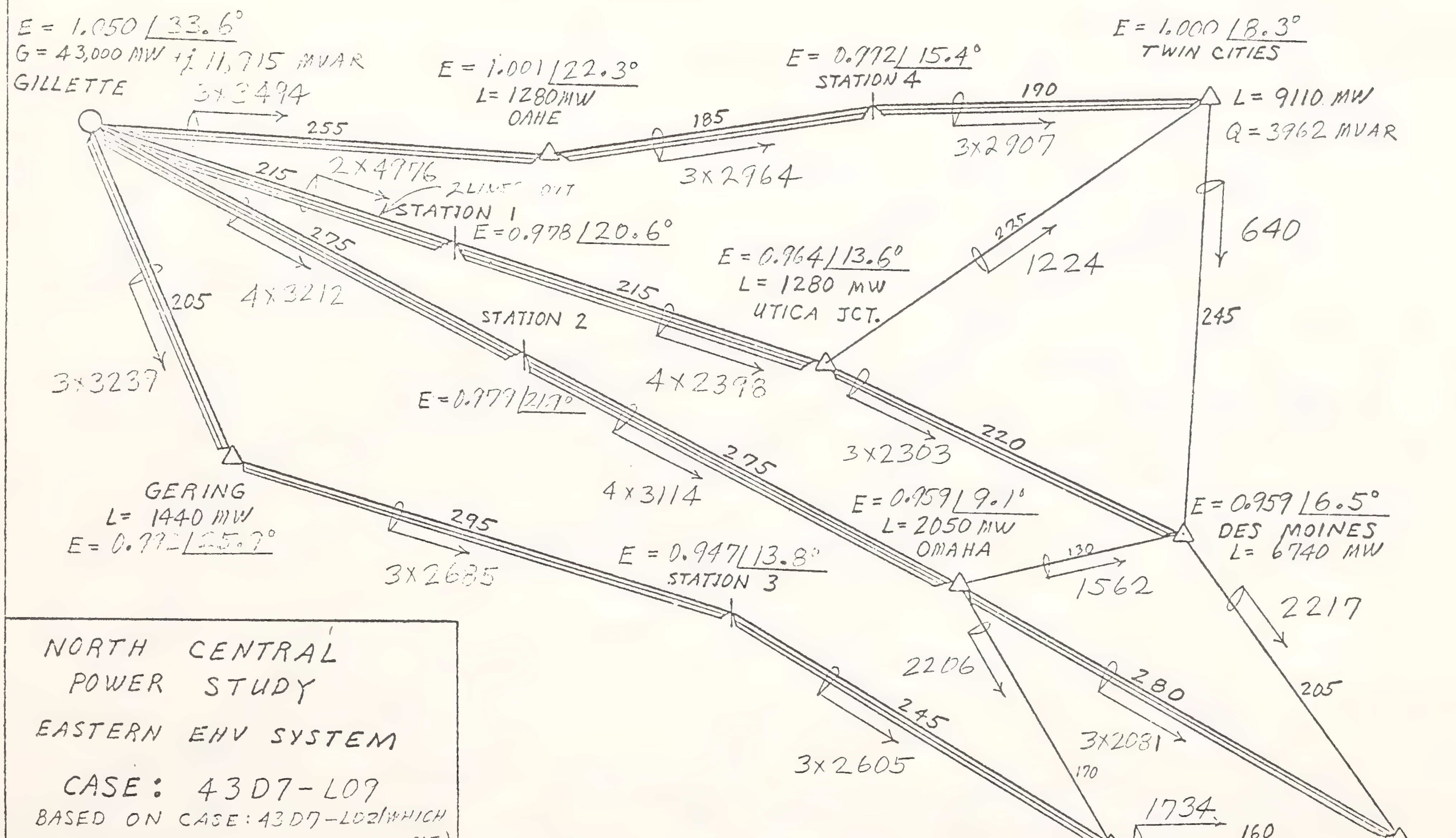


E = 1.050 ∠23.0°
G = 43,000 MW + j 11,767 MVAR
GILLETTE
2X4516
255
3X3713
ONE LINE OUT
215
275
4X3155
205
3X3203
GERING
L= 1440 MW
E = 0.992 ∠18.2°
L= 1280MW
OAHE
185
3X2470
E = 0.990 ∠12.4°
STATION 4
190
3X2429
E = 1.000 ∠16.4°
TWIN CITIES
L = 9110 MW
Q = 3769 MVAR
13
245
2006
275
E = 0.967 ∠14.8°
L = 1280 MW
UTICA JCT.
STATION 1
E = 0.990 ∠23.0°
215
4 X 2851
220
3X2623
STATION 2
E = 0.981
275
4X3060
295
3X2650
E = 0.948 ∠13.5°
STATION 3
245
3X2573
E = 0.960 ∠9.0°
L = 2050 MW
OMAHA
2239
130
1363
E = 0.960 ∠6.7°
DES MOINES
L = 6740 MW
2320
205
280
3X2068
170
KANSAS CITY
L = 8060MW
E = 0.946 ∠4.0°
1677
160
MONTGOMERY
L = 10,150 MW
E = 1.000 ∠10.0°
TOTAL LOAD = 40,110 MW
MW LOSSES = 3077
MVAR LOSSES = 22,449
LINE COMPENSATION:
500KV - 765KV - 80%
NORTH CENTRAL POWER STUDY
EASTERN EHV SYSTEM
CASE: 4307-L06
BASED ON CASE: 4307-L01 (WHICH
GILLETTE-OAHE LINE CUT.)
GILLETTE-STATION 1 OUTAGE.



E = 1.050 ∠33.8°
G = 43,000 MW + j 12,012 MVAR
GILLETTE
2×4416
255
ONE LINE OUT
E = 0.973 ∠19.2°
L = 1280 MW
OAHE
185
3×2438
E = 0.990 ∠13.4°
STATION 4
190
3×2399
E = 1.000 ∠7.5°
TWIN CITIES
L = 9110 MW
Q = 3143 MVAR
215
4×3238
STATION 1
E = 0.998 ∠25.6°
275
3×3767
ONE LINE OUT
205
3×3270
STATION 2
E = 0.971 ∠19.4°
4×2725
275
215
4×3161
E = 0.969 ∠16.7°
L = 1280 MW
UTICA JCT.
275
2189
101
245
3×2958
220
GERING
L = 1440 MW
E =
295
3×2714
E = 0.946 ∠13.8°
STATION 3
E = 0.958 ∠8.6°
L = 2050 MW
OMAHA
130
606
E = 0.959 ∠7.6°
DES MOINES
L = 6740 MW
2616
205
2052
280
3×1962
245
3×2632
170
1663
160
KANSAS CITY
L = 8060 MW
E = 0.944 ∠4.0°
MONTGOMERY
L = 10,150 MW
G = 225 + j 6671 MVA.
E = 1.000 ∠0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L07
BASED ON CASE: 43D7-L01 (WHICH HAS ONE GILLETTE-OAHE LINE OUT)
WITH A GILLETTE-STATION 2 OUTAGE.
TOTAL LOAD = 40,110 MW
MW LOSSES = 3115
MVAR LOSSES = 22,626
LINE COMPENSATION:
500KV - 765 KV - 80%
Run:
Recorded:


E = 1.050 ∠33.3°
G = 43,000 MW +j 12,017 MVAR
GILLETTE
2×4417
255
ONE LINE OUT
E = 0.974 ∠18.8°
L = 1280 MW
OAHE
185
3×2409
E = 0.971 ∠13.2°
STATION 4
190
3×2370
E = 1.000 ∠7.3°
TWIN CITIES
L = 9110 MW
Q = 3858 MVAR
25
245
215
4×3181
STATION 1
E = 0.979 ∠25.2°
275
2197
E = 0.970 ∠16.5°
L = 1280 MW
UTICA JCT.
205
4×3167
275
215
STATION 2
2×4386
ONE LINE OUT
E = 0.980 ∠21.0°
4×3107
3×2886
220
4×3071
275
GERING
L = 1440 MW
E = 0.975 ∠22.6°
295
3×2353
E = 0.942 ∠11.8°
STATION 3
E = 0.959 ∠9.1°
L = 2050 MW
OMAHA
130
910
E = 0.960 ∠7.6°
DES MOINES
L = 6740 MW
2640
2652
280
205
245
3×2290
3×2097
170
1264
160
KANSAS CITY
L = 8060 MW
E = 0.943 ∠3.2°
MONTGOMERY
L = 10,150 MW
G = 20412 6644 MVA
E = 1.000 ∠0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L08
BASED ON CASE: 43D7-L01 (WHICH
HAS ONE GILLETTE-OAHE LINE OUT.)
WITH A GILLETTE-GERING OUTAGE.
TOTAL LOAD = 40,110 MW
MW LOSSES = 3094
MVAR LOSSES = 22,521
LINE COMPENSATION:
500KV - 765 KV - 80%
Run:
Recorded:



NORTH CENTRAL
POWER STUDY

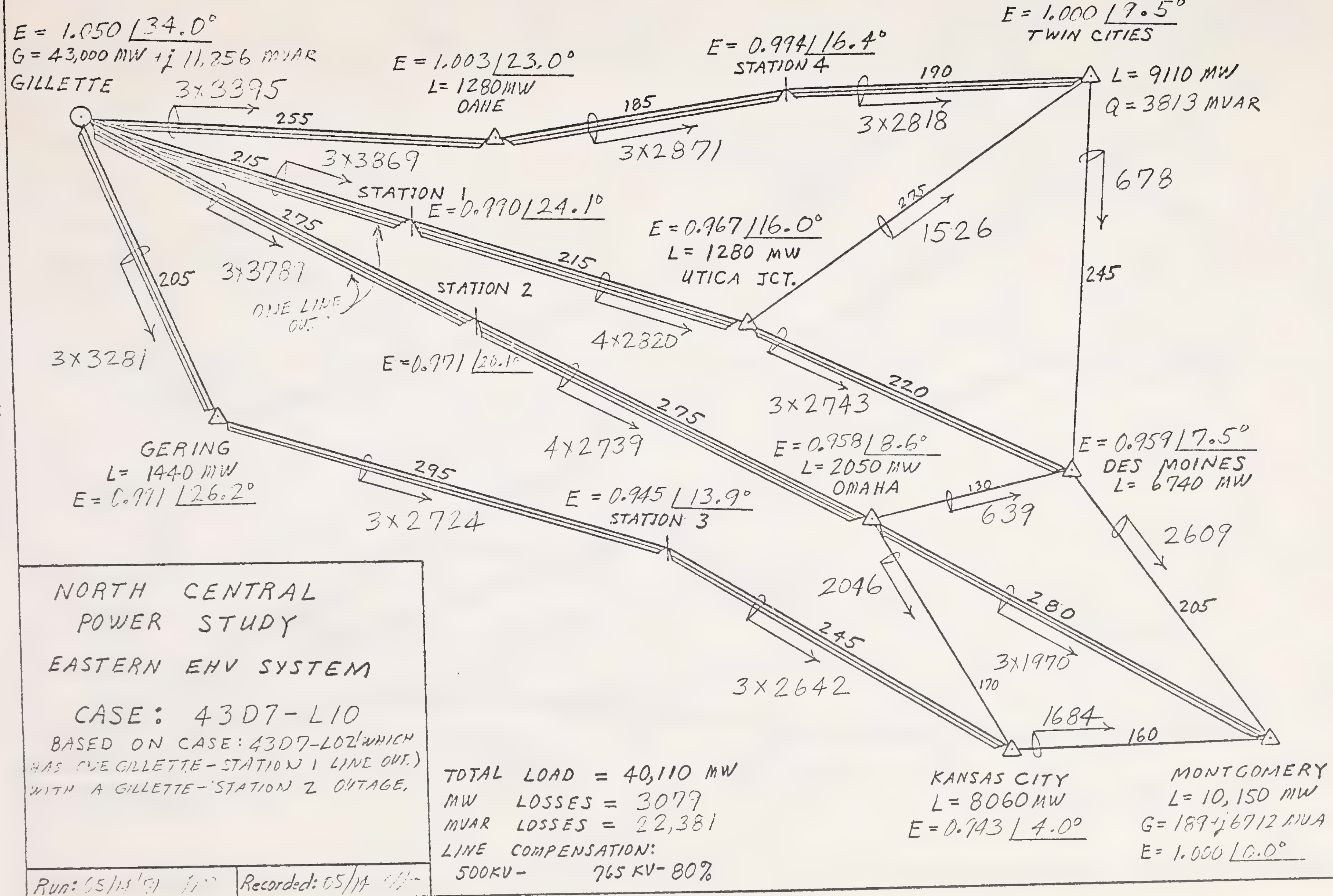
EASTERN EHV SYSTEM

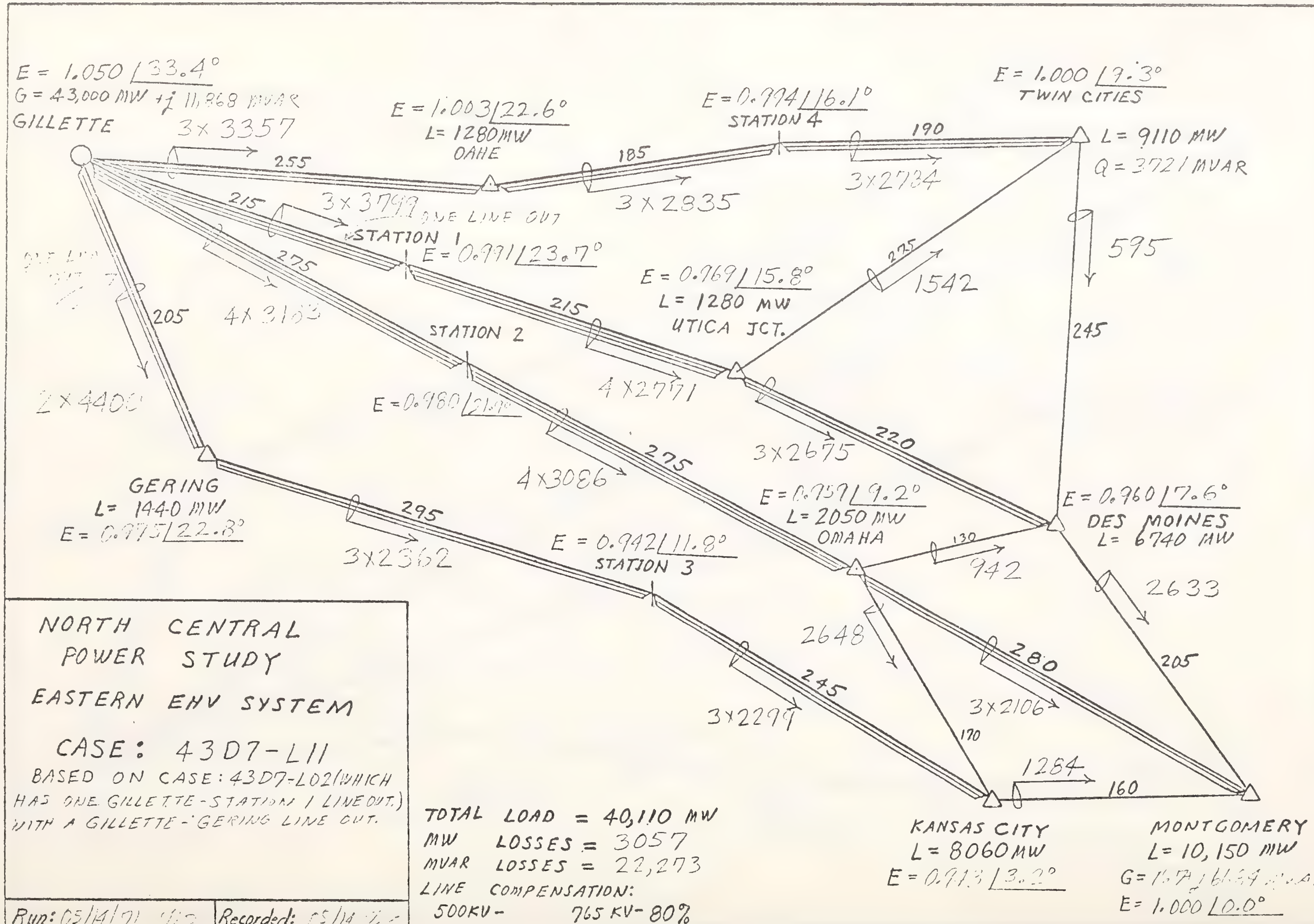
CASE: 43D7-L07

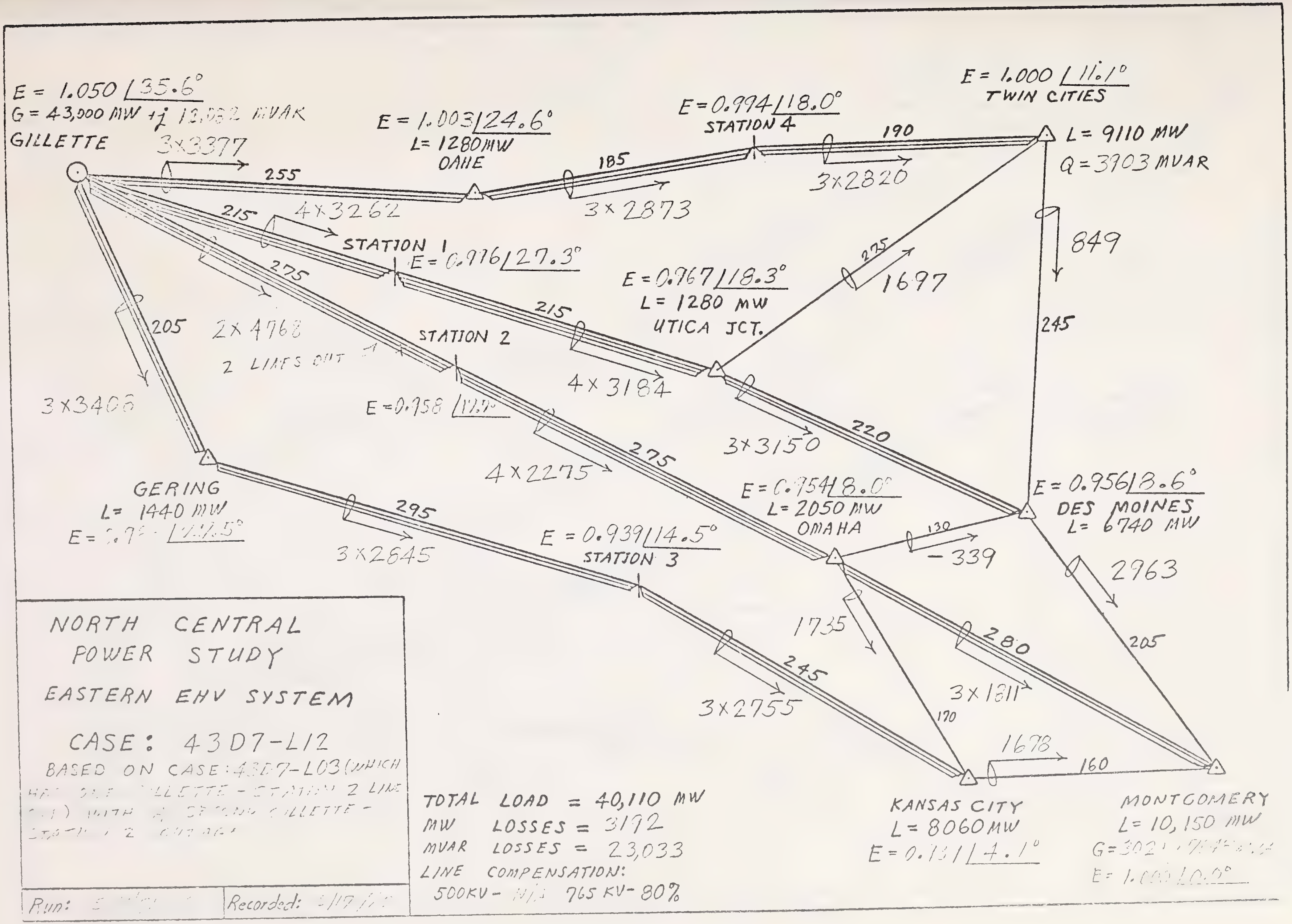
BASED ON CASE: 43D7-L02 (WHICH HAS ONE GILLETTE-STATION 1 LINE OUT.) WITH AN OUTAGE OF A SECOND GILLETTE-STATION 1 LINE.

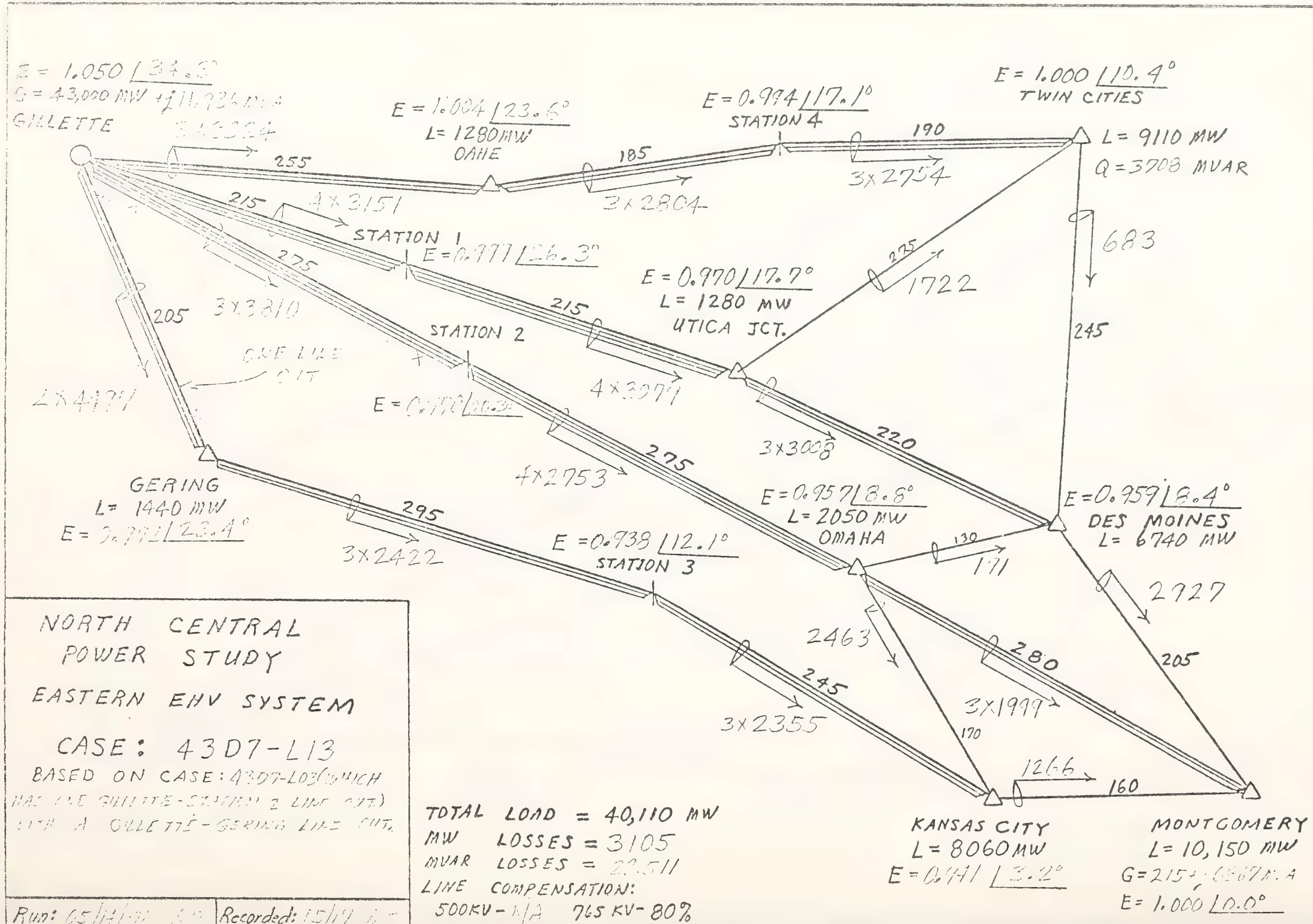
Run: | Recorded:

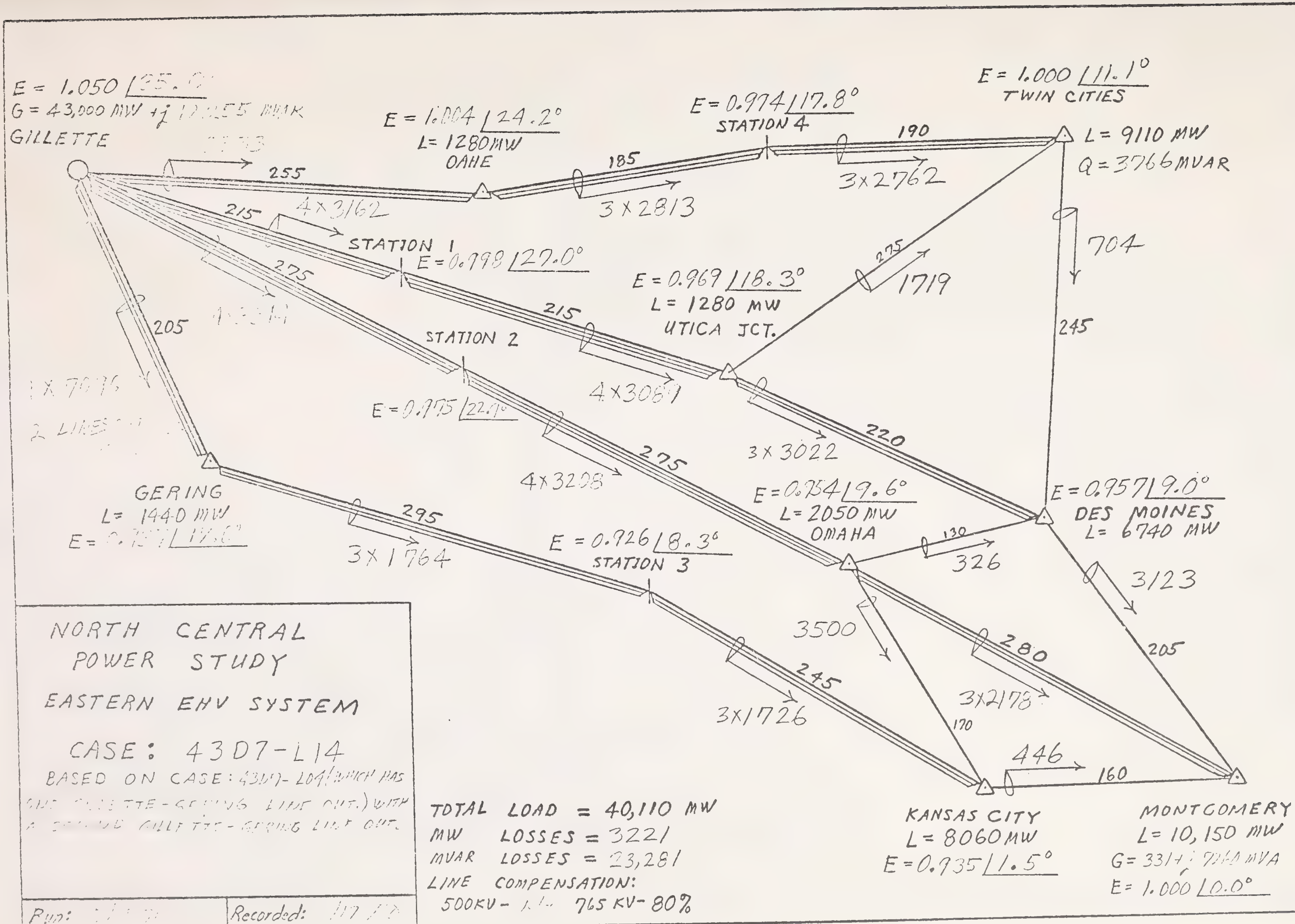
TOTAL LOAD = 40,110 MW
MW LOSSES = 3087
MVAR LOSSES = 22,517
LINE COMPENSATION:
500KV - 765 KV - 80%

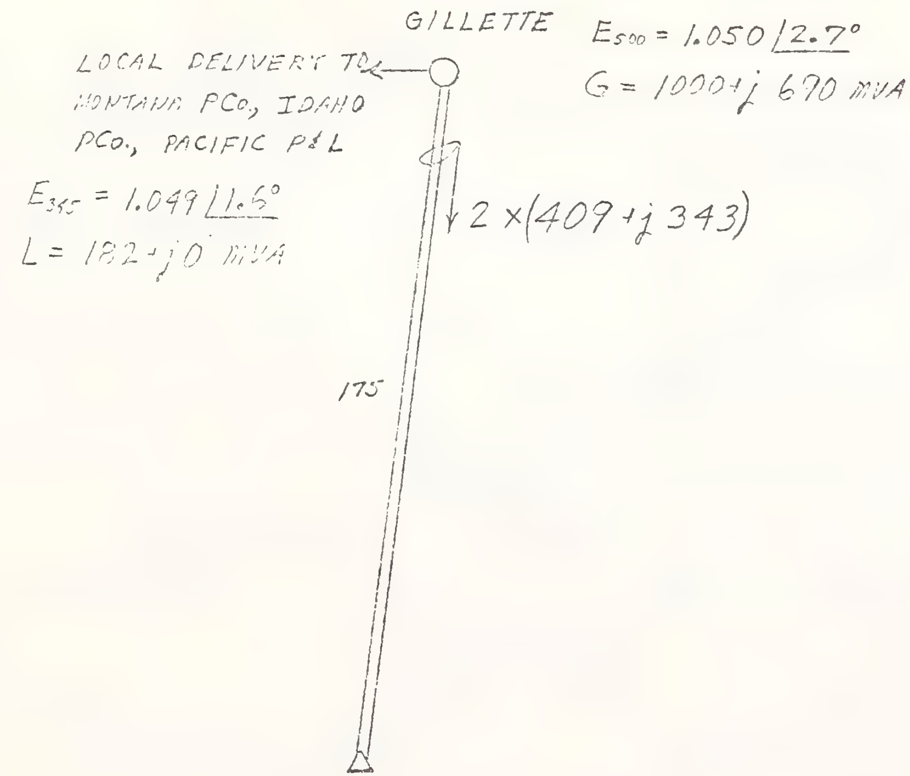

E = 1.050 /34.0°
G = 43,000 MW + j 11,256 MVAR
GILLETTE
3×3395
255
E = 1.003 /23.0°
L= 1280 MW
OAHE
185
3×2871
E = 0.994 /16.4°
STATION 4
190
3×2818
E = 1.000 /7.5°
TWIN CITIES
L = 9110 MW
Q = 3813 MVAR
678
245
215
3×3869
STATION 1
E = 0.990 /24.1°
275
3×3787
ONE LINE OUT!
205
3×3281
STATION 2
E = 0.971 /20.1°
215
4×2820
E = 0.967 /16.0°
L = 1280 MW
UTICA JCT.
275
1526
220
3×2743
275
4×2739
GERING
L= 1440 MW
E = 0.991 /26.2°
295
3×2724
E = 0.945 /13.9°
STATION 3
E = 0.958 /8.6°
L = 2050 MW
OMAHA
130
639
E = 0.959 /7.5°
DES MOINES
L= 6740 MW
2609
205
2046
280
3×1970
170
245
3×2642
1684
160
KANSAS CITY
L = 8060 MW
E = 0.943 /4.0°
MONTGOMERY
L = 10,150 MW
G = 189 + j 6712 MVA
E = 1.000 /0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 4307-L10
BASED ON CASE: 4307-L02 (WHICH HAS ONE GILLETTE - STATION 1 LINE OUT.)
WITH A GILLETTE - STATION 2 OUTAGE.
TOTAL LOAD = 40,110 MW
MW LOSSES = 3079
MVAR LOSSES = 22,381
LINE COMPENSATION:
500KV - 765 KV - 80%
Run: 05/11/'91
Recorded: 05/14


E = 1.050 ∠33.4°
G = 43,000 MW +j 11,868 MVAR
GILLETTE
3 × 3357
255
E = 1.003 ∠22.6°
L = 1280 MW
OAHE
185
3 × 2835
E = 0.994 ∠16.1°
STATION 4
190
3×2734
E = 1.000 ∠9.3°
TWIN CITIES
L = 9110 MW
Q = 3721 MVAR
595
245
215
3 × 3799 ONE LINE OUT
STATION 1
E = 0.991 ∠23.7°
275
4 × 3163
205
2 × 4400
215
4 × 2771
E = 0.969 ∠15.8°
L = 1280 MW
UTICA JCT.
275
1542
STATION 2
E = 0.980 ∠21.9°
4 × 3086
275
220
3×2675
GERING
L = 1440 MW
E = 0.975 ∠22.8°
295
3×2362
E = 0.942 ∠11.8°
STATION 3
245
3×2299
E = 0.959 ∠9.2°
L = 2050 MW
OMAHA
130
942
E = 0.960 ∠7.6°
DES MOINES
L = 6740 MW
2633
2648
170
280
3×2106
205
1284
160
KANSAS CITY
L = 8060 MW
E = 0.913 ∠3.2°
MONTGOMERY
L = 10,150 MW
E = 1.000 ∠0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L11
BASED ON CASE: 43D7-L02 (WHICH HAS ONE GILLETTE-STATION 1 LINE OUT.)
WITH A GILLETTE-GERING LINE OUT.
TOTAL LOAD = 40,110 MW
MW LOSSES = 3057
MVAR LOSSES = 22,273
LINE COMPENSATION:
500KV -
765 KV - 80%
Run: 05/14/71
Recorded: 05/14


E = 1.050 ∠35.6°
G = 43,000 MW
GILLETTE
3x3377
255
4x3262
215
275
2x4768
2 LINES OUT
205
3x3406
E = 1.003 ∠24.6°
L= 1280 MW
OAHE
185
3 x 2873
E=0.994 ∠18.0°
STATION 4
190
3x2820
E = 1.000 ∠11.1°
TWIN CITIES
L= 9110 MW
Q = 3903 MVAR
849
245
STATION 1
E=0.976 ∠27.3°
215
4 x 3184
E = 0.967 ∠18.3°
L = 1280 MW
UTICA JCT.
275
1697
STATION 2
E = 0.958
4 x 2275
275
220
3x3150
GERING
L= 1440 MW
295
3 x 2845
E = 0.939 ∠14.5°
STATION 3
245
3x2755
E = 0.954 ∠18.0°
L = 2050 MW
OMAHA
130
-339
E = 0.956 ∠18.6°
DES MOINES
L= 6740 MW
2963
205
1735
280
3x1811
170
1678
160
KANSAS CITY
L = 8060 MW
MONTGOMERY
L= 10,150 MW
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L12
BASED ON CASE: 43D7-L03 (WHICH
TOTAL LOAD = 40,110 MW
MW LOSSES = 3192
MVAR LOSSES = 23,033
LINE COMPENSATION:
500KV - 765 KV - 80%
Run:
Recorded:


E = 1.000 /10.4°
TWIN CITIES
L = 9110 MW
Q = 3708 MVAR
GILLETTE
E = 1.004 /23.6°
L= 1280 MW
OAHE
E = 0.994 /17.1°
STATION 4
255
185
190
3x2804
3x2754
4x3151
215
STATION 1
275
3x3810
205
ONE LINE
CUT
STATION 2
E = 0.970 /17.7°
L = 1280 MW
UTICA JCT.
275
1722
683
245
215
4x3979
220
3x3008
GERING
L= 1440 MW
295
3x2422
4x2753
275
E = 0.957 /8.8°
L = 2050 MW
OMAHA
E = 0.959 /8.4°
DES MOINES
L = 6740 MW
130
171
2727
E = 0.938 /12.1°
STATION 3
2463
280
205
245
3x2355
3x1999
170
1266
160
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L13
BASED ON CASE: 43D7-L03
TOTAL LOAD = 40,110 MW
MW LOSSES = 3105
LINE COMPENSATION:
500KV - N/A 765 KV - 80%
KANSAS CITY
L = 8060 MW
MONTGOMERY
L = 10,150 MW
E = 1.000 /0.0°
Run:
Recorded:


E = 1.050
G = 43,000 MW +j
GILLETTE
255
4×3162
215
275
205
E = 1.004 ∠24.2°
L = 1280 MW
OAHE
185
3 × 2813
E = 0.974 ∠17.8°
STATION 4
190
3×2762
E = 1.000 ∠11.1°
TWIN CITIES
L = 9110 MW
Q = 3766 MVAR
704
245
STATION 1
E = 0.998 ∠27.0°
215
4×3089
E = 0.969 ∠18.3°
L = 1280 MW
UTICA JCT.
275
1719
220
3 × 3022
STATION 2
275
4×3208
GERING
L = 1440 MW
295
3 × 1764
E = 0.926 ∠8.3°
STATION 3
245
3×1726
E = 0.954 ∠9.6°
L = 2050 MW
OMAHA
130
326
3500
170
280
3×2178
E = 0.957 ∠9.0°
DES MOINES
L = 6740 MW
3123
205
446
160
KANSAS CITY
L = 8060 MW
E = 0.935 ∠1.5°
MONTGOMERY
L = 10,150 MW
E = 1.000 ∠0.0°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
CASE: 43D7-L14
BASED ON CASE:
TOTAL LOAD = 40,110 MW
MW LOSSES = 3221
MVAR LOSSES = 23,281
LINE COMPENSATION:
765 KV- 80%
Run:
Recorded:



MEDICINE BOW
$E = 1.000 \angle 0.0°$
$L = 7$[illegible] $+ j\,0$ MVA
$G = -25 - j\,628$ MVA

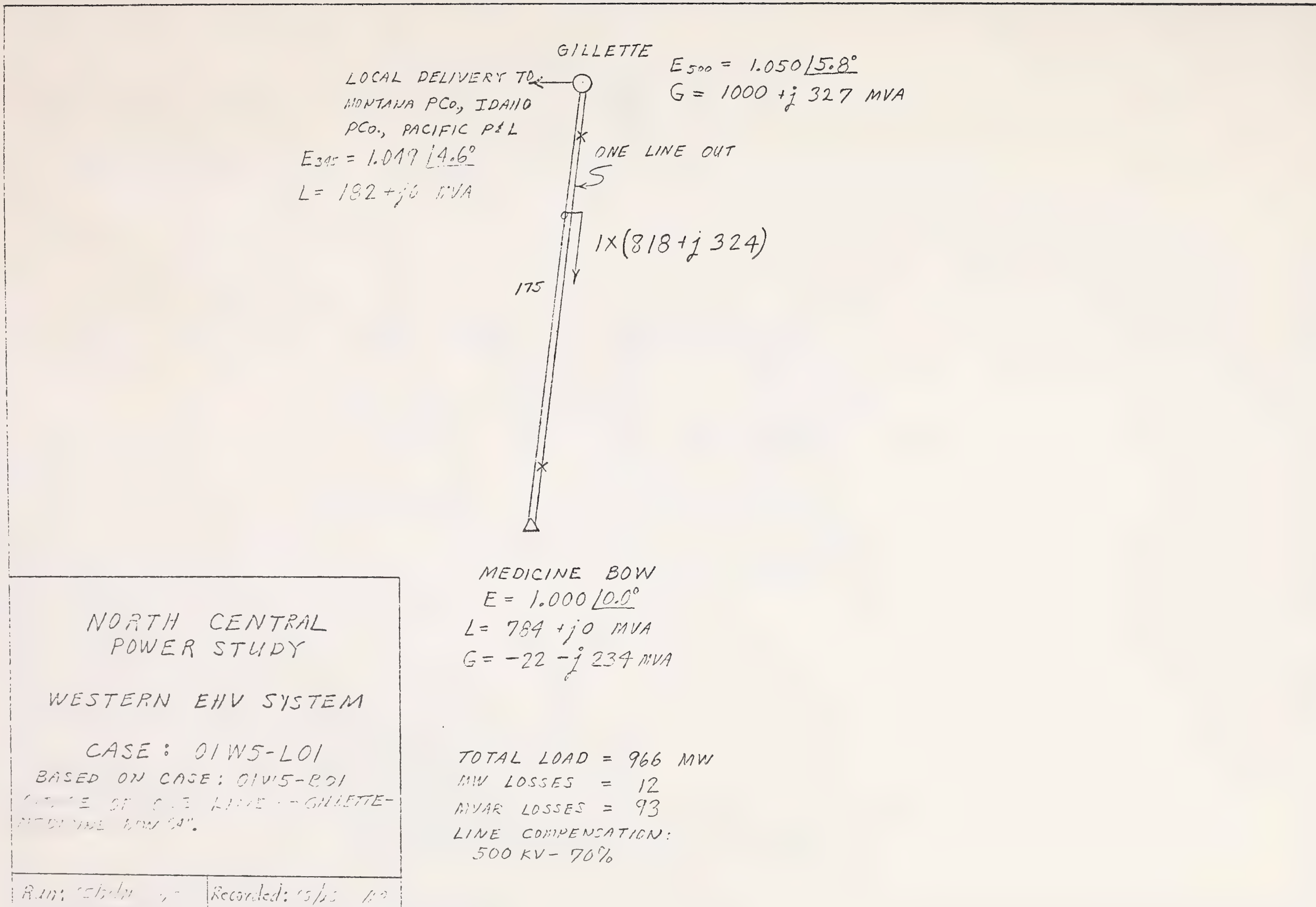
TOTAL LOAD = 966 MW
MW LOSSES = 9
MVAR LOSSES = 62
LINE COMPENSATION:
500 KV – 70%

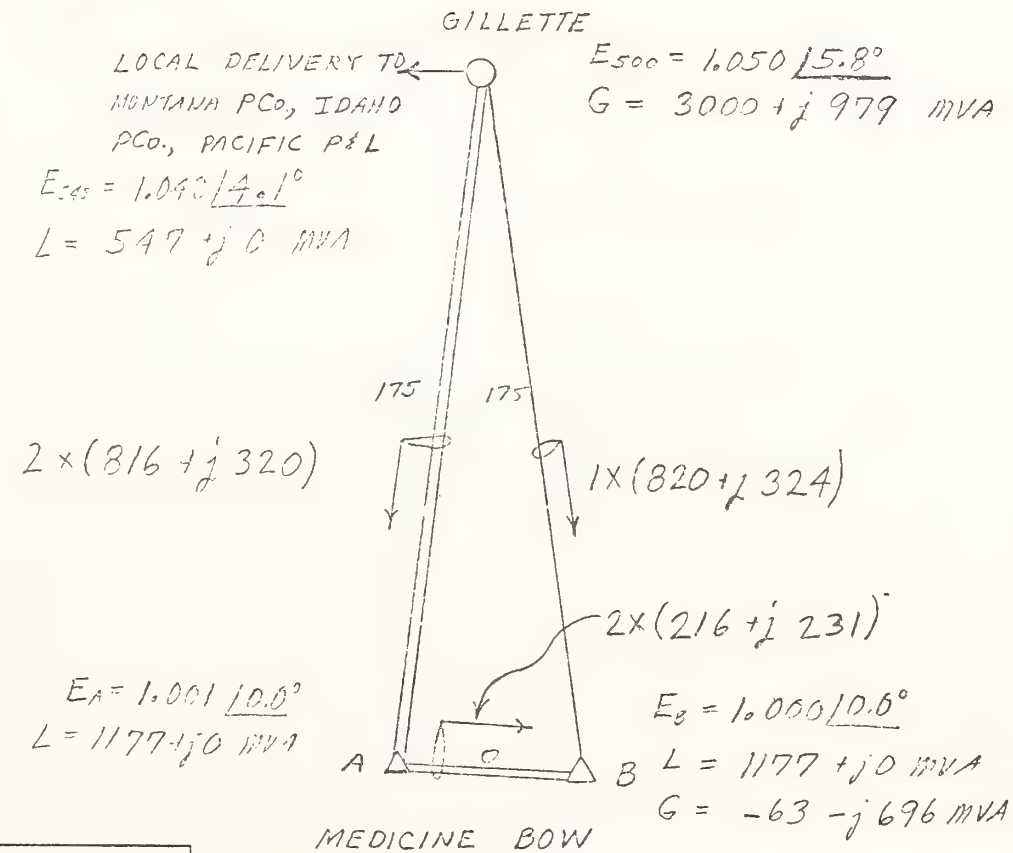
NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE: 01W5-B01
BASED ON CASE: None

Run: [illegible] | Recorded: [illegible]


GILLETTE
E500 = 1.050 ∠5.8°
G = 1000 + j 327 MVA
LOCAL DELIVERY TO:
MONTANA PCo, IDAHO
PCo., PACIFIC P&L
E345 = 1.019 ∠4.6°
L = 182 + j0 MVA
ONE LINE OUT
1X(818 + j 324)
175
MEDICINE BOW
E = 1.000 ∠0.0°
L = 784 + j0 MVA
G = −22 − j 234 MVA
TOTAL LOAD = 966 MW
MW LOSSES = 12
MVAR LOSSES = 93
LINE COMPENSATION:
500 KV − 70%
NORTH CENTRAL
POWER STUDY
WESTERN EHV SYSTEM
CASE: 01W5-L01
BASED ON CASE: 01W5-B01
Run:
Recorded:



NORTH CENTRAL
POWER STUDY

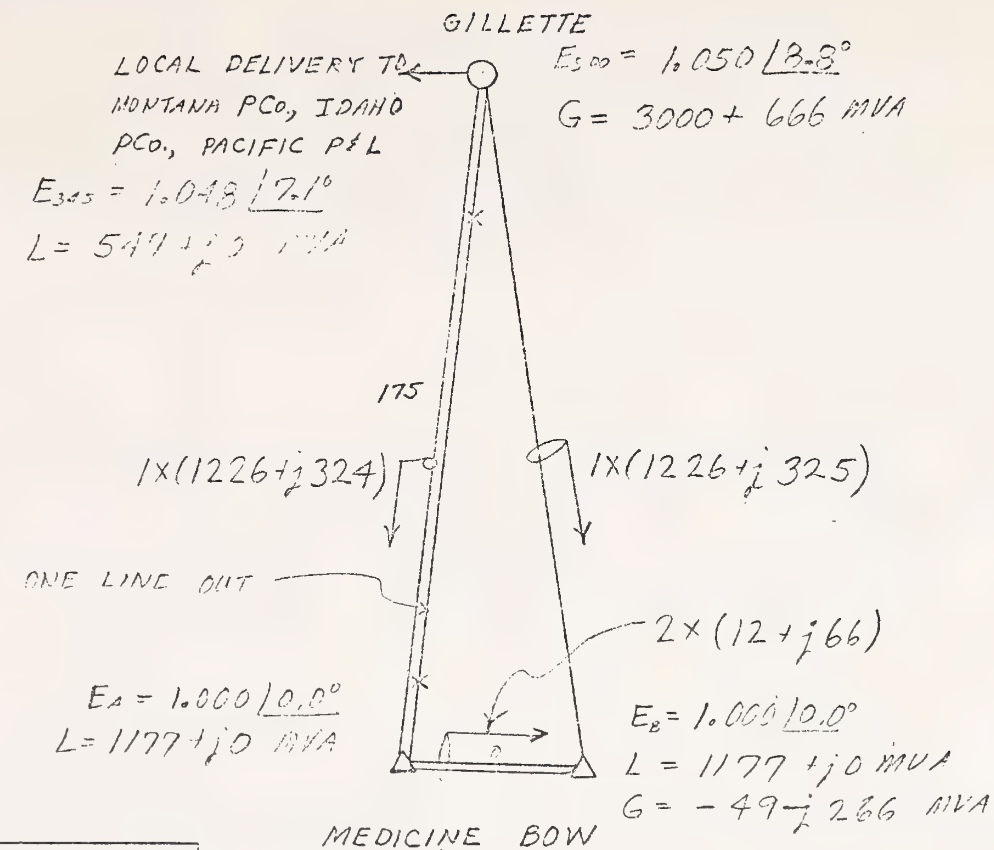
WESTERN EHV SYSTEM

CASE: 03W5-B01

BASED ON CASE: 01W5-B01
ADDED A NEW BUS AT MEDICINE
BOW "B" - AND ONE LINE TO GILLETTE
PLUS TWO TIES TO "A" BUS.

Run:	Recorded:

TOTAL LOAD = 1901 MW
MW LOSSES = 36
MVAR LOSSES = 283
LINE COMPENSATION:
500KV - 70%



NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE: 03W5-L01

BASED ON CASE: 03W5-B01

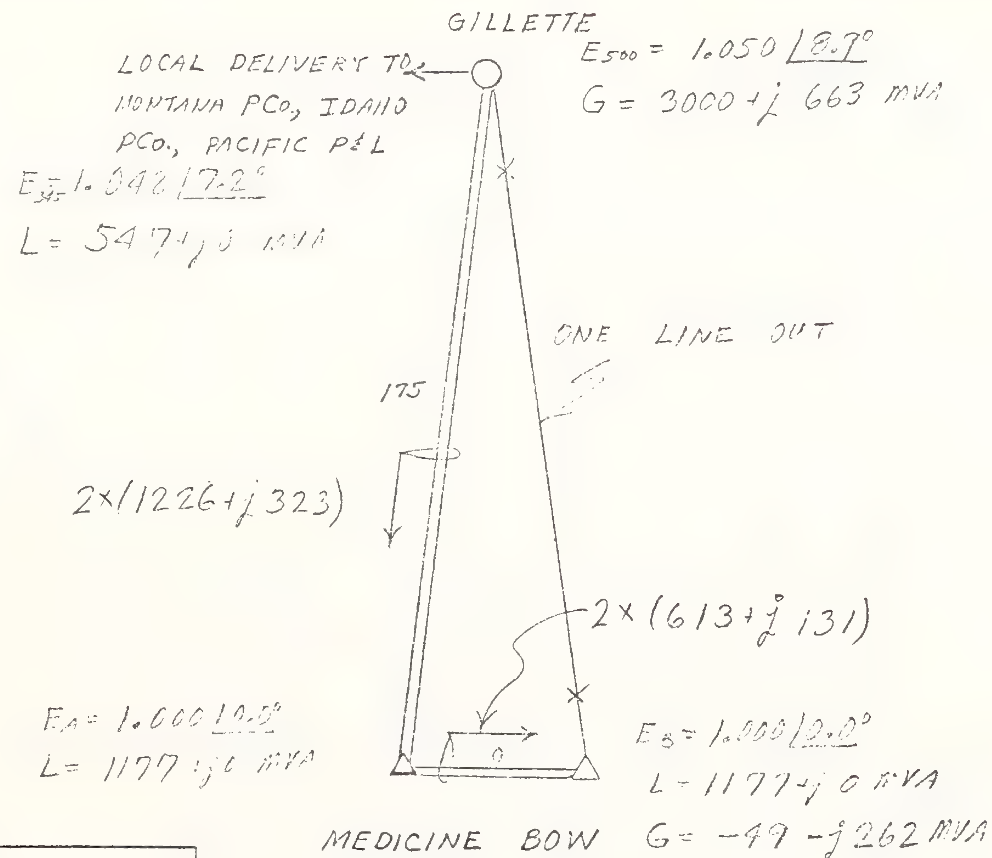
Run: | Recorded:

TOTAL LOAD = 1901 MW

MW LOSSES = 50

MVAR LOSSES = 400

LINE COMPENSATION:
500KV - 70%



NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

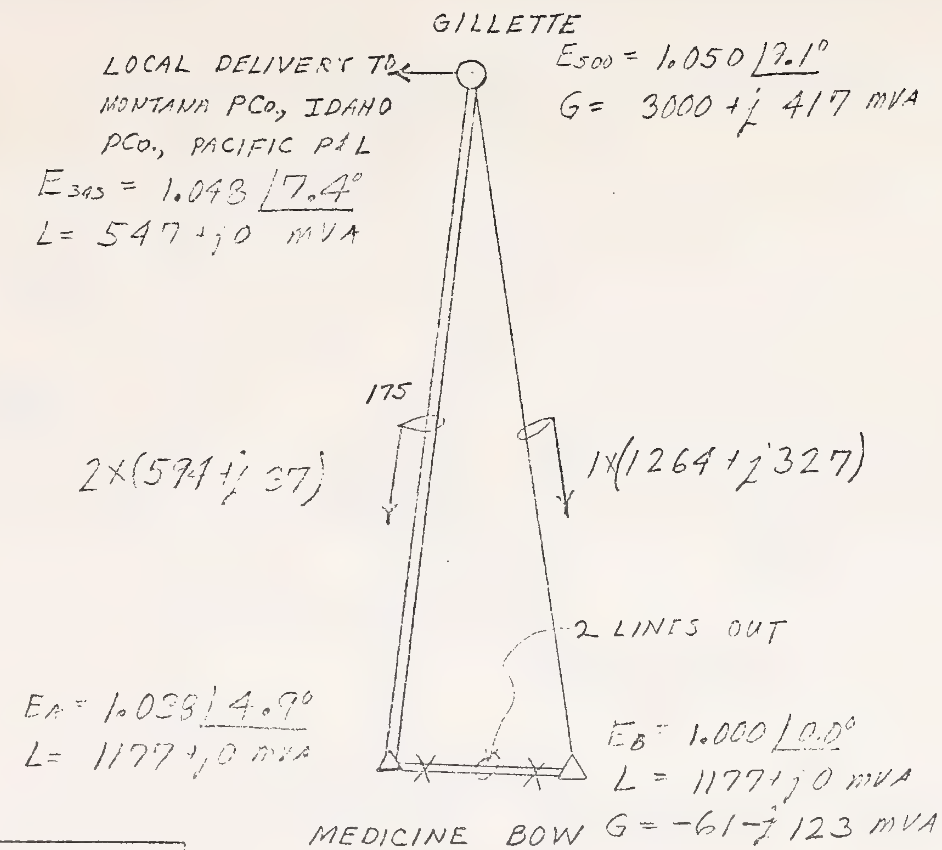
CASE : 03W5-L02

BASED ON CASE : 03W5-B01

OUTAGE OF ONE LINE -- GILLETTE-MEDICINE BOW "B".

Run: 05/10/71 7/10	Recorded: 05/25 7/10

TOTAL LOAD = 1901 MW
MW LOSSES = 50
MVAR LOSSES = 402
LINE COMPENSATION:
500KV - 70%



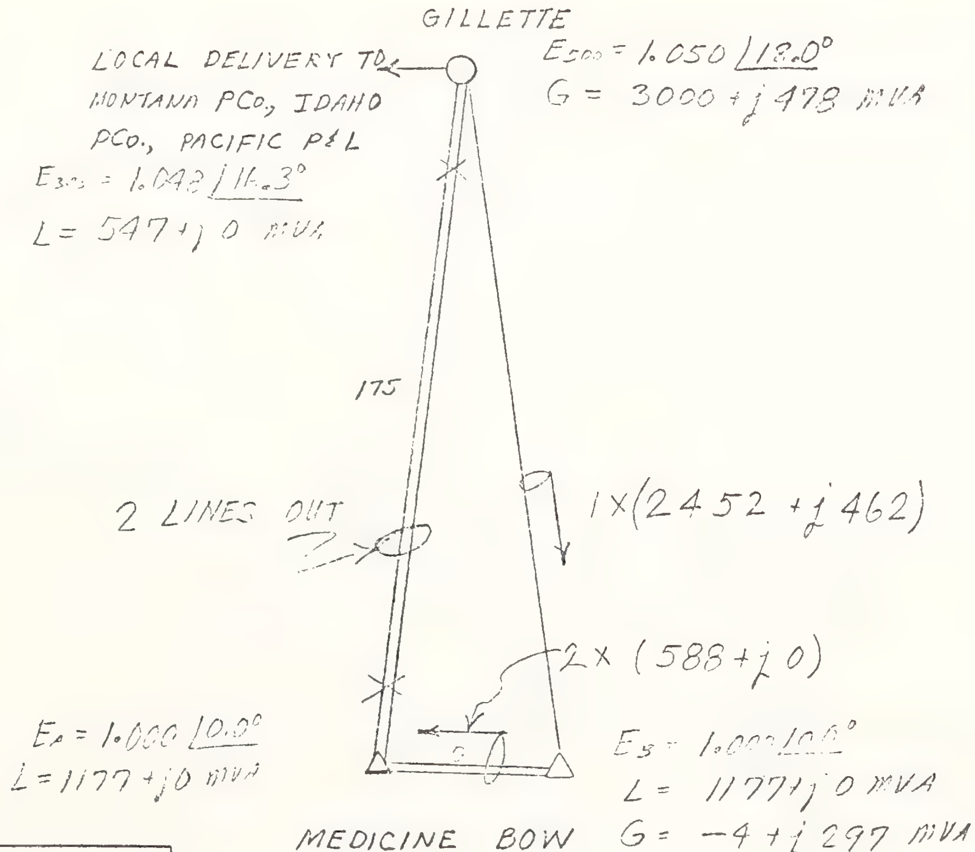
NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE : 03W5-L03

BASED ON CASE: 03W5-B01
OUTAGE OF TWO LINES -- BOTH
MEDICINE BOW A-B TIES.

TOTAL LOAD = 1901 MW
MW LOSSES = 38
MVAR LOSSES = 294
LINE COMPENSATION:
500KV - 70%



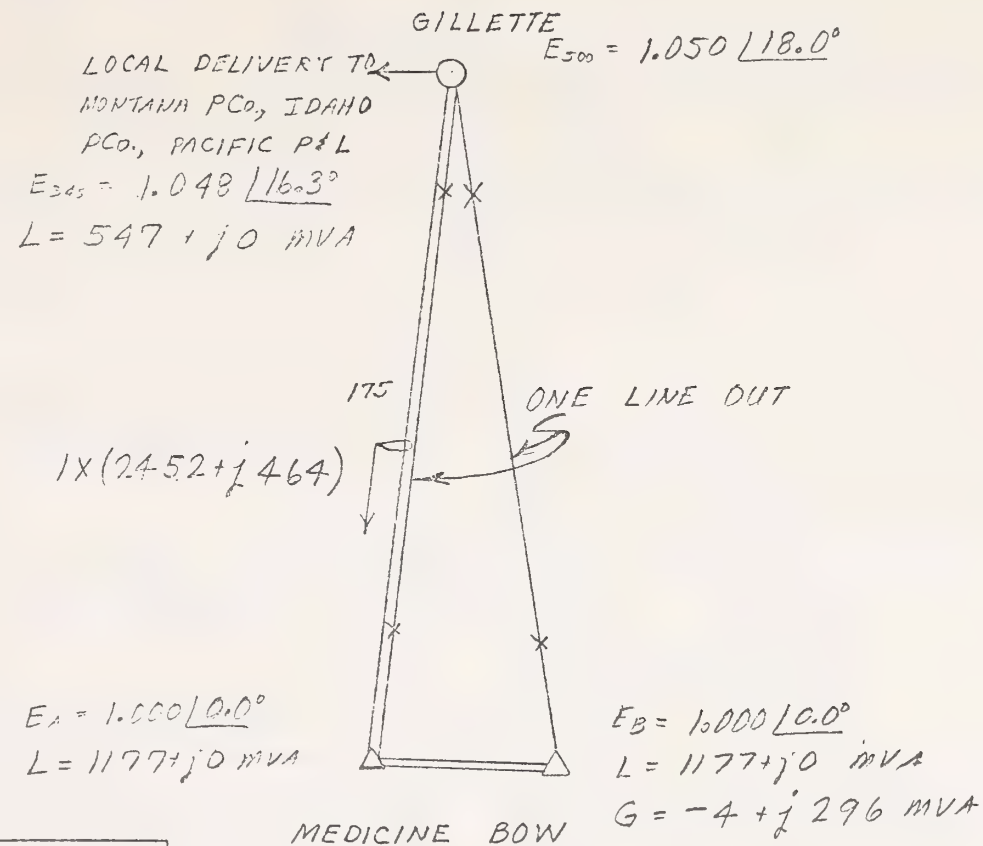
NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE: 03W5-L04
BASED ON CASE: 03W5-B01
OUTAGE OF TWO LINES -- BOTH GILLETTE-MEDICINE BOW "A" LINES.

Run: 05/31/71	Recorded: 05/25/71

TOTAL LOAD = 1701 MW
MW LOSSES = 95
MVAR LOSSES = 775
LINE COMPENSATION:
500KV - 70%



NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE : 03W5 - L05

BASED ON CASE : 03W5 - B01

[illegible] TWO LINES -- ONE EACH

[illegible] "A" AND "B".

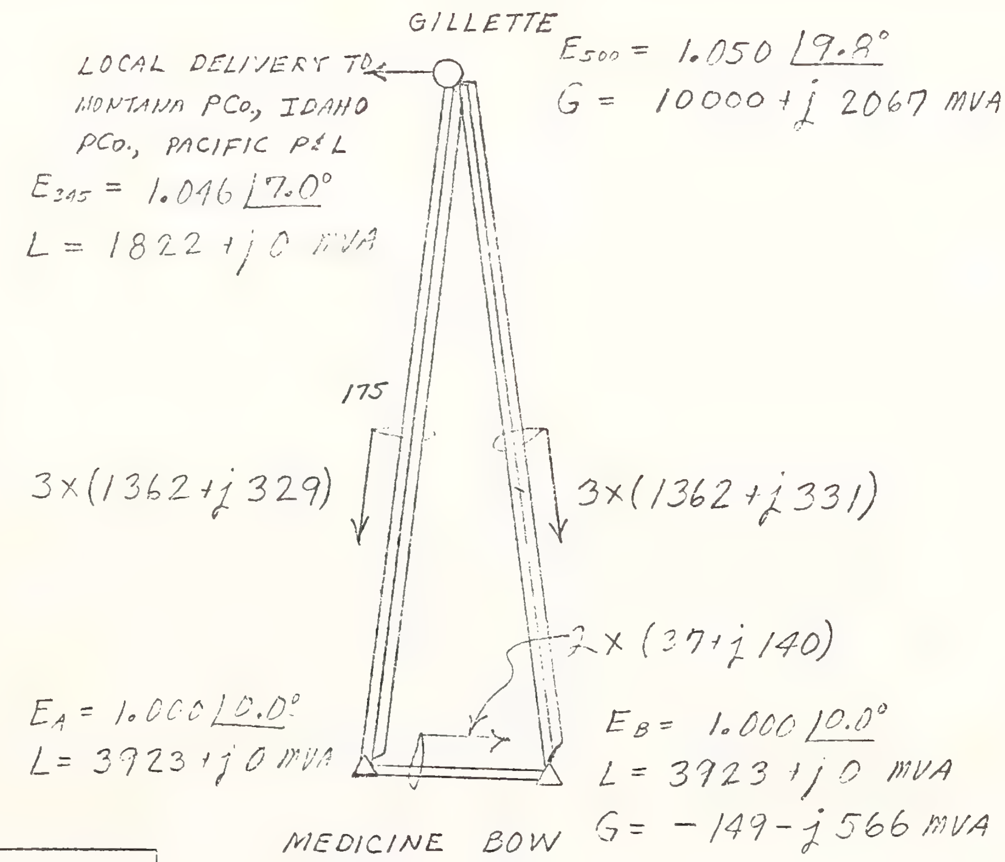
Run: [illegible] | Recorded: [illegible]

TOTAL LOAD = 1901 MW

MW LOSSES = 95

MVAR LOSSES = 775

LINE COMPENSATION:
500KV - 70%



NORTH CENTRAL
POWER STUDY

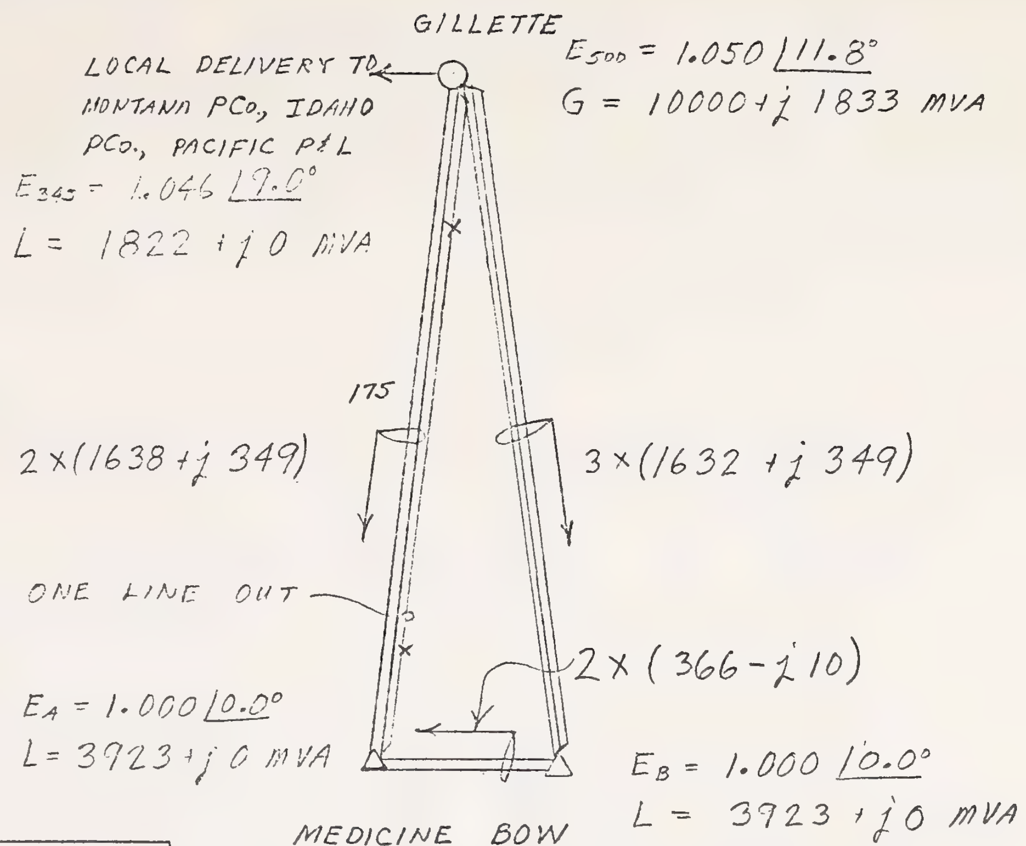
WESTERN EHV SYSTEM

CASE: 10W5-B01

BASED ON CASE: [illegible] - B01
ADDED ONE GILLETTE-MEDICINE BOW "A" AND TWO GILLETTE-MEDICINE BOW "B" LINES.

Run: [illegible] | Recorded: [illegible]

TOTAL LOAD = 9668 MW
MW LOSSES = 183
MVAR LOSSES = 1501
LINE COMPENSATION:
500KV - 70%



NORTH CENTRAL
POWER STUDY

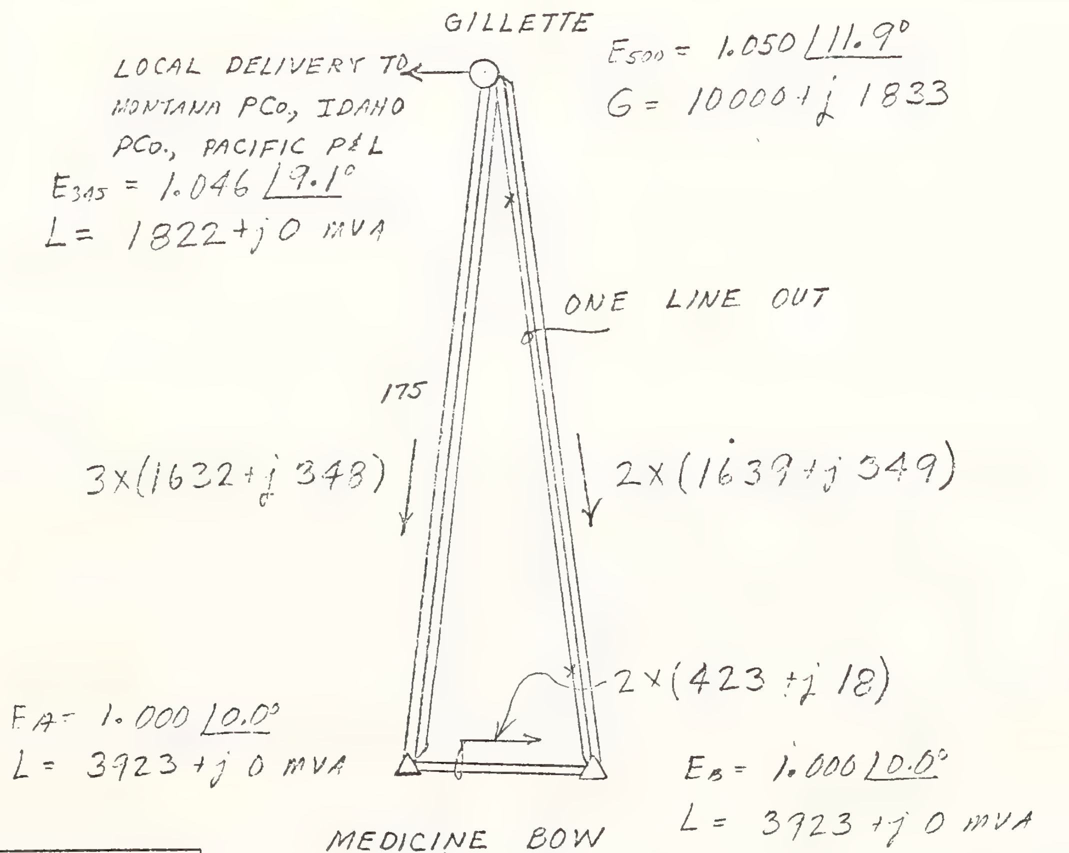
WESTERN EHV SYSTEM

CASE : 10W5-L01

BASED ON CASE: 10W5-301
OUTAGE OF ONE LINE -- GILLETTE-
MEDICINE BOW "A".

Run: [illegible] | Recorded: 05/25 [illegible]

TOTAL LOAD = 9668 MW
MW LOSSES = 216
MVAR LOSSES = 1775
LINE COMPENSATION:
500 KV - 70%



NORTH CENTRAL
POWER STUDY

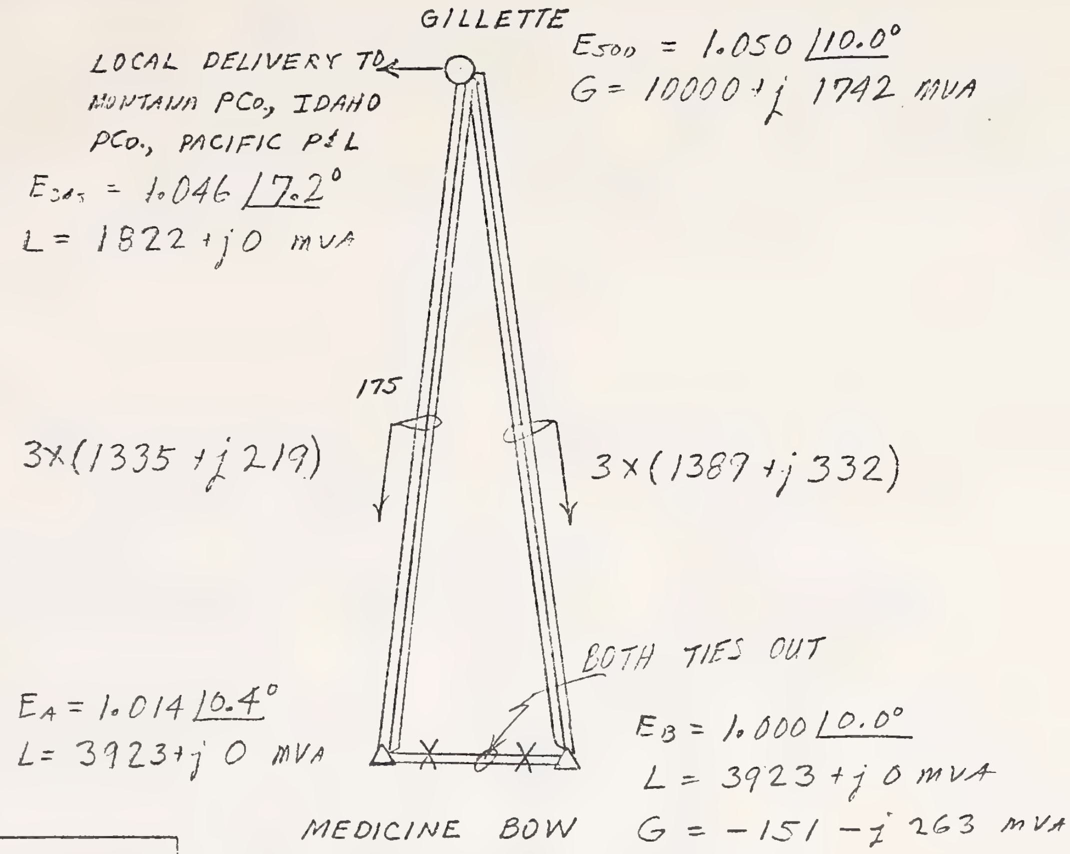
WESTERN EHV SYSTEM

CASE: 10W5-L02

BASED ON CASE: 10W5-B01
OUTAGE OF ONE LINE--GILLETTE-MEDICINE BOW "B".

Run: 05/20/71 | Recorded: 05/25

TOTAL LOAD = 9668 MW
MW LOSSES = 216
MVAR LOSSES = 1776
LINE COMPENSATION:
500 KV - 70%



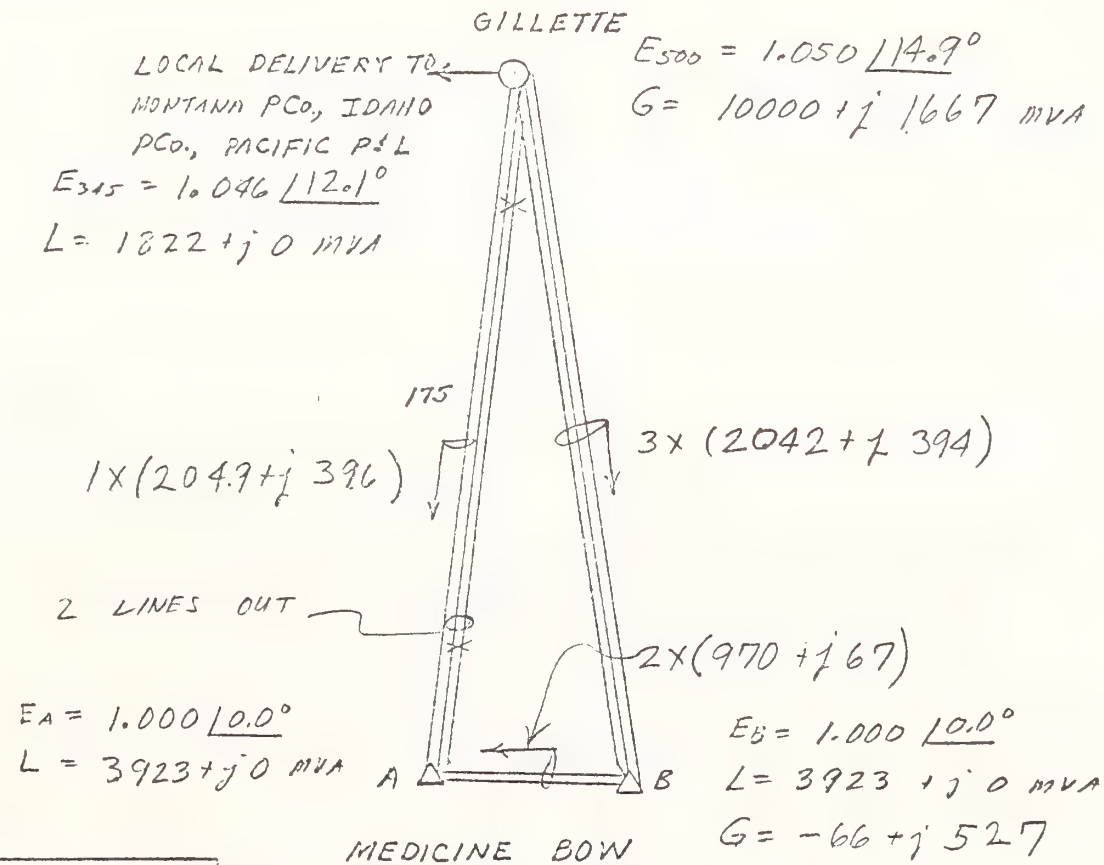
NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE: 10W5-L03
BASED ON CASE: 10W5-B01
OUTAGE OF TWO LINES -- BOTH
MEDICINE BOW A-B TIES

Run: [illegible]	Recorded: [illegible]

TOTAL LOAD = 9668 MW
MW LOSSES = 181
MVAR LOSSES = 1479
LINE COMPENSATION:
500KV - 70%



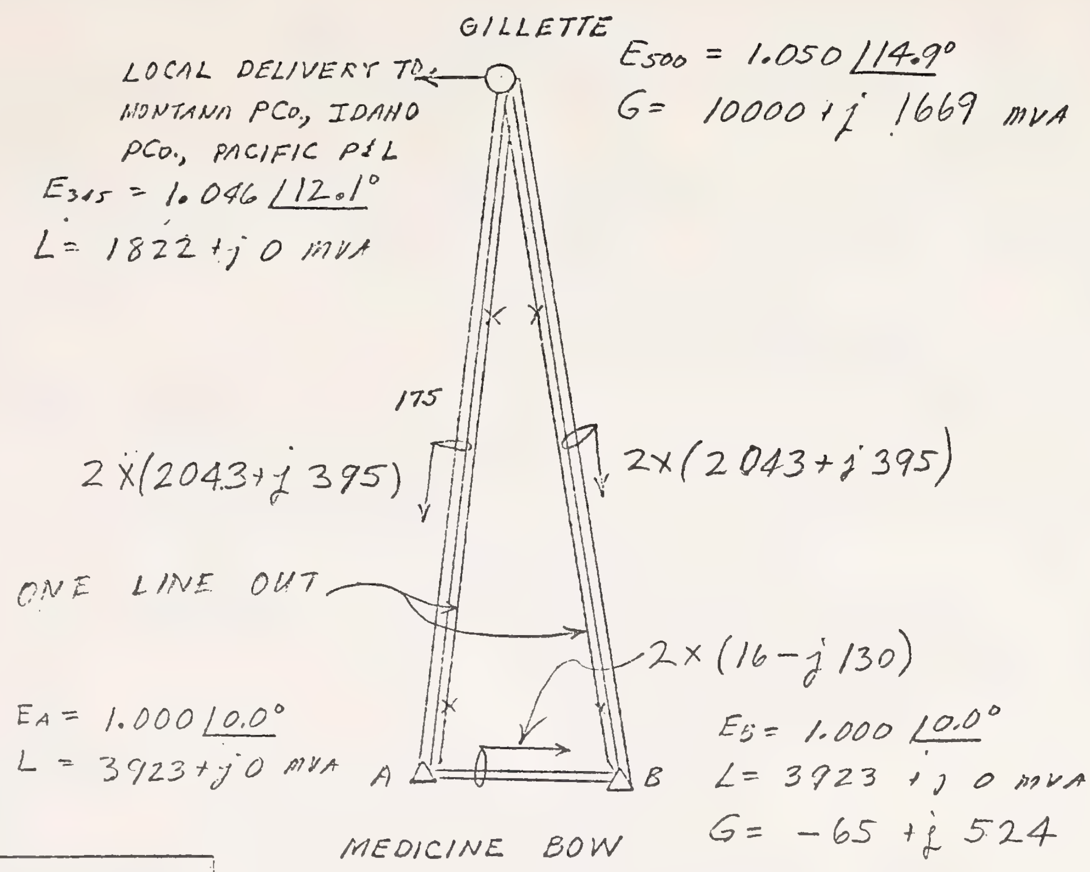
NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

CASE : 10W5-L04
BASED ON CASE: 10W5-B01
OUTAGE OF TWO LINES-- TWO:
GILLETTE - MEDICINE BOW "A" LINES

TOTAL LOAD = 9668 MW
MW LOSSES = 266
MVAR LOSSES = 2194
LINE COMPENSATION:
500 KV - 70%

Run: 05/21/71 | Recorded: 05/25



NORTH CENTRAL
POWER STUDY

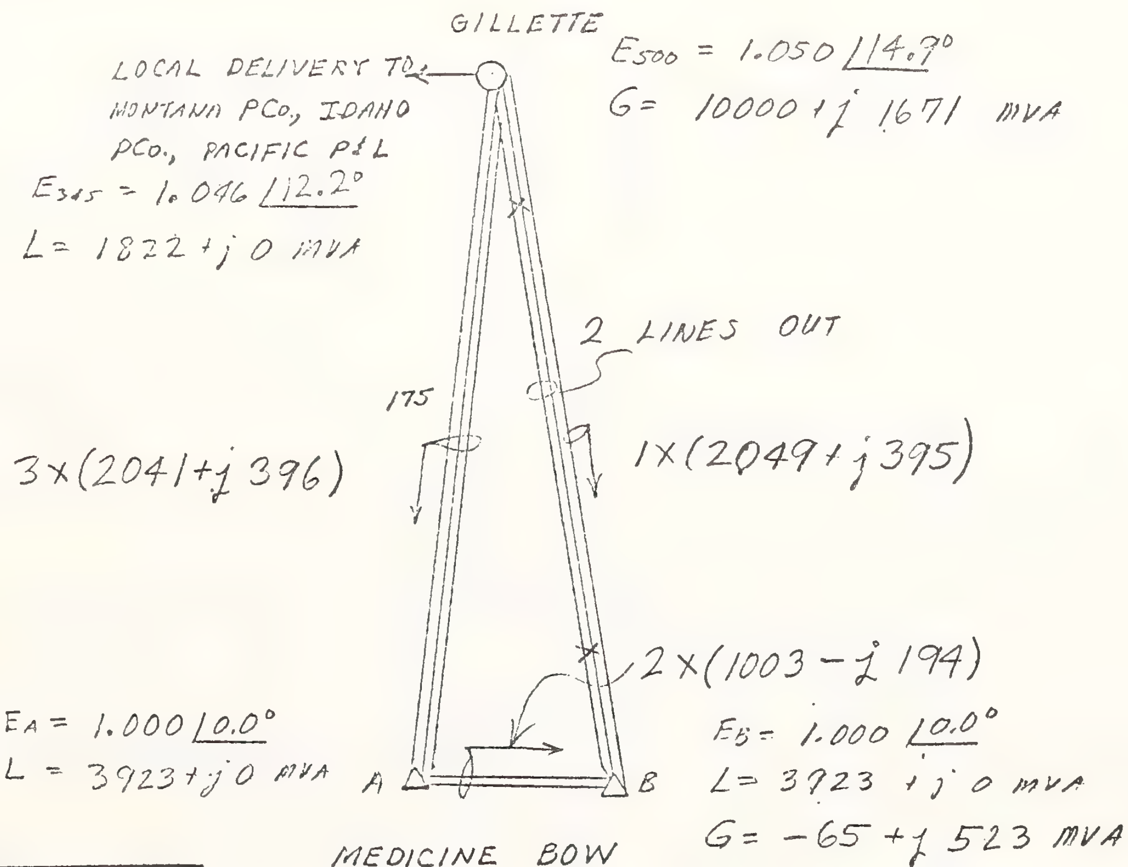
WESTERN EHV SYSTEM

CASE: 10W5-L05

BASED ON CASE: 10W5-B01
OUTAGE OF TWO LINES - ONE EACH
GILLETTE - MEDICINE BOW 'A' AND 'B'

Run: 05/21/71 | Recorded: 05/25/70

TOTAL LOAD = 9668 MW
MW LOSSES = 267
MVAR LOSSES = 2193
LINE COMPENSATION:
500 KV - 70%



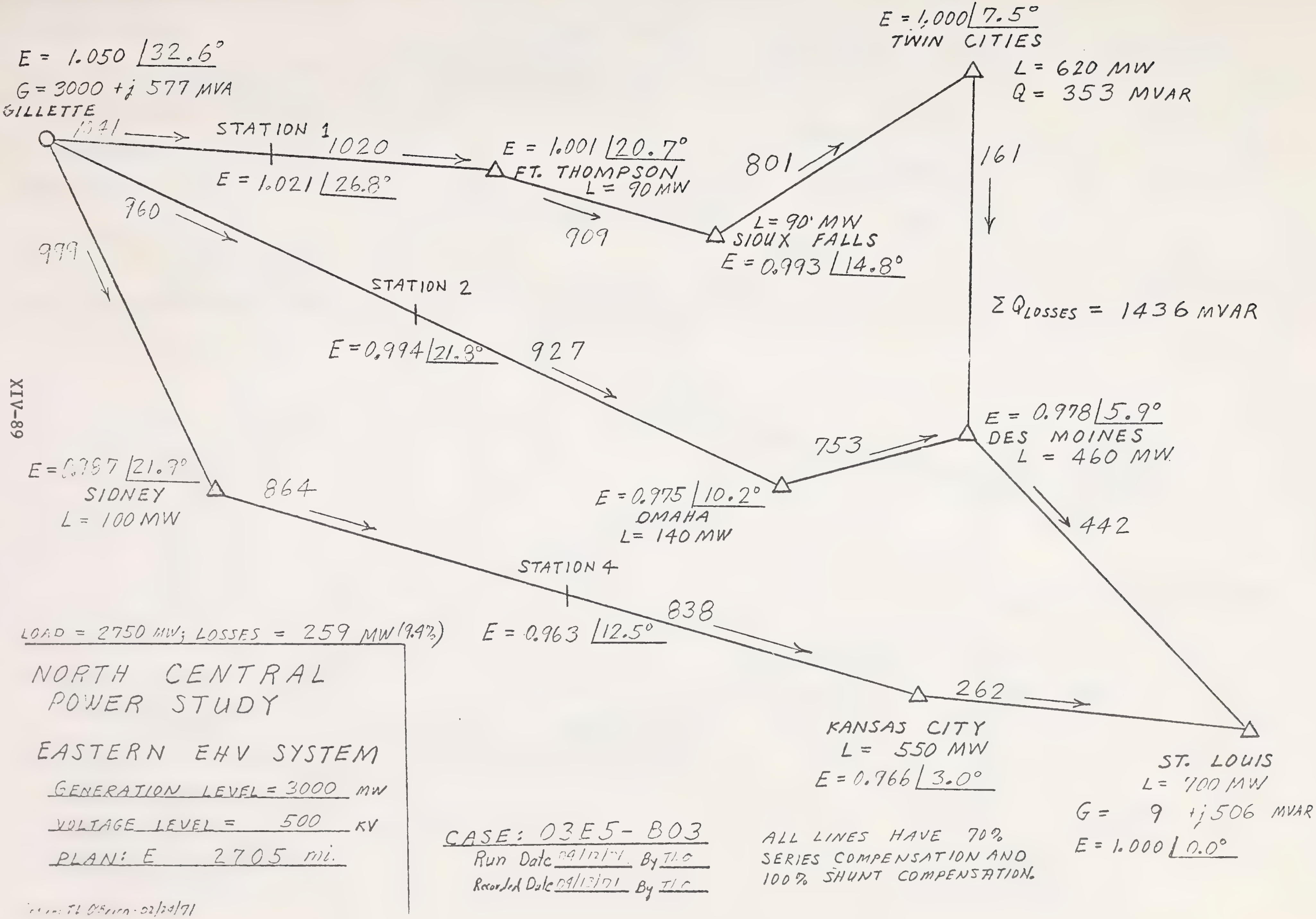
NORTH CENTRAL
POWER STUDY

WESTERN EHV SYSTEM

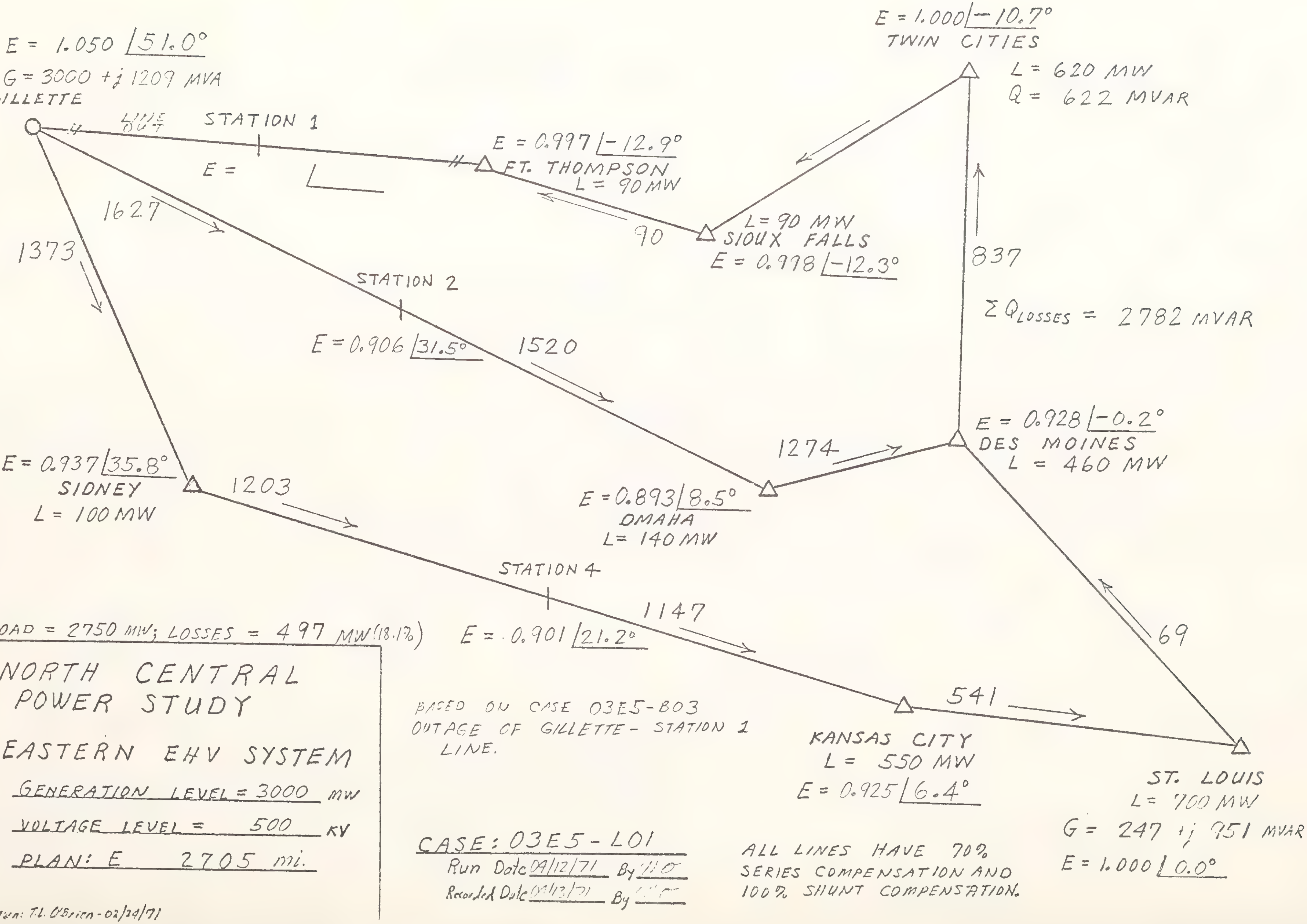
CASE: 10W5-L06
BASED ON CASE: 10W5-B01:
OUTAGE OF TWO LINES — BOTH
GILLETTE - MEDICINE BOW "B" LINES.

Run: 05/21/71 740	Recorded: 05/25 /70

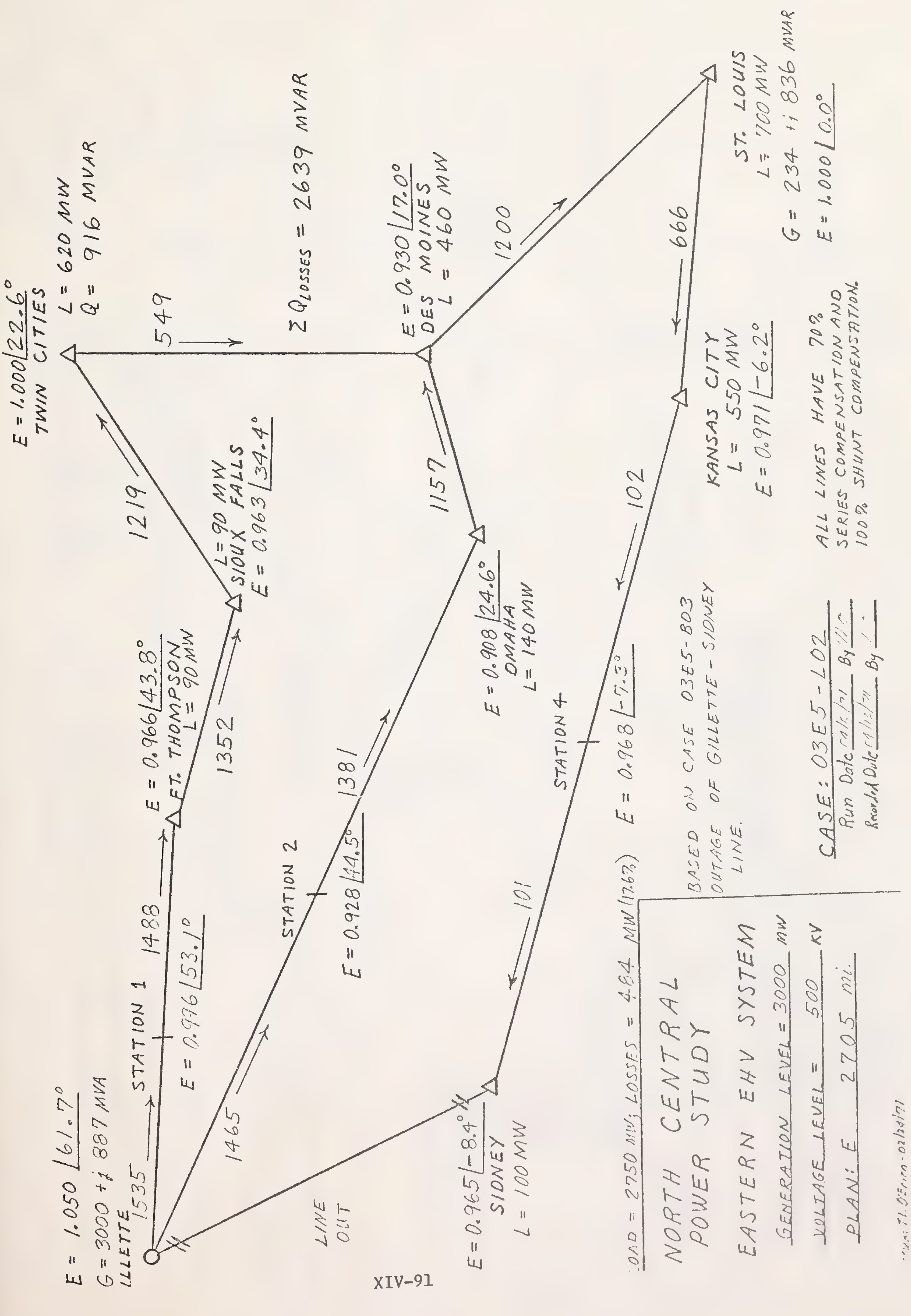
TOTAL LOAD = 9668 MW
MW LOSSES = 267
MVAR LOSSES = 2194
LINE COMPENSATION:
500 KV - 70%

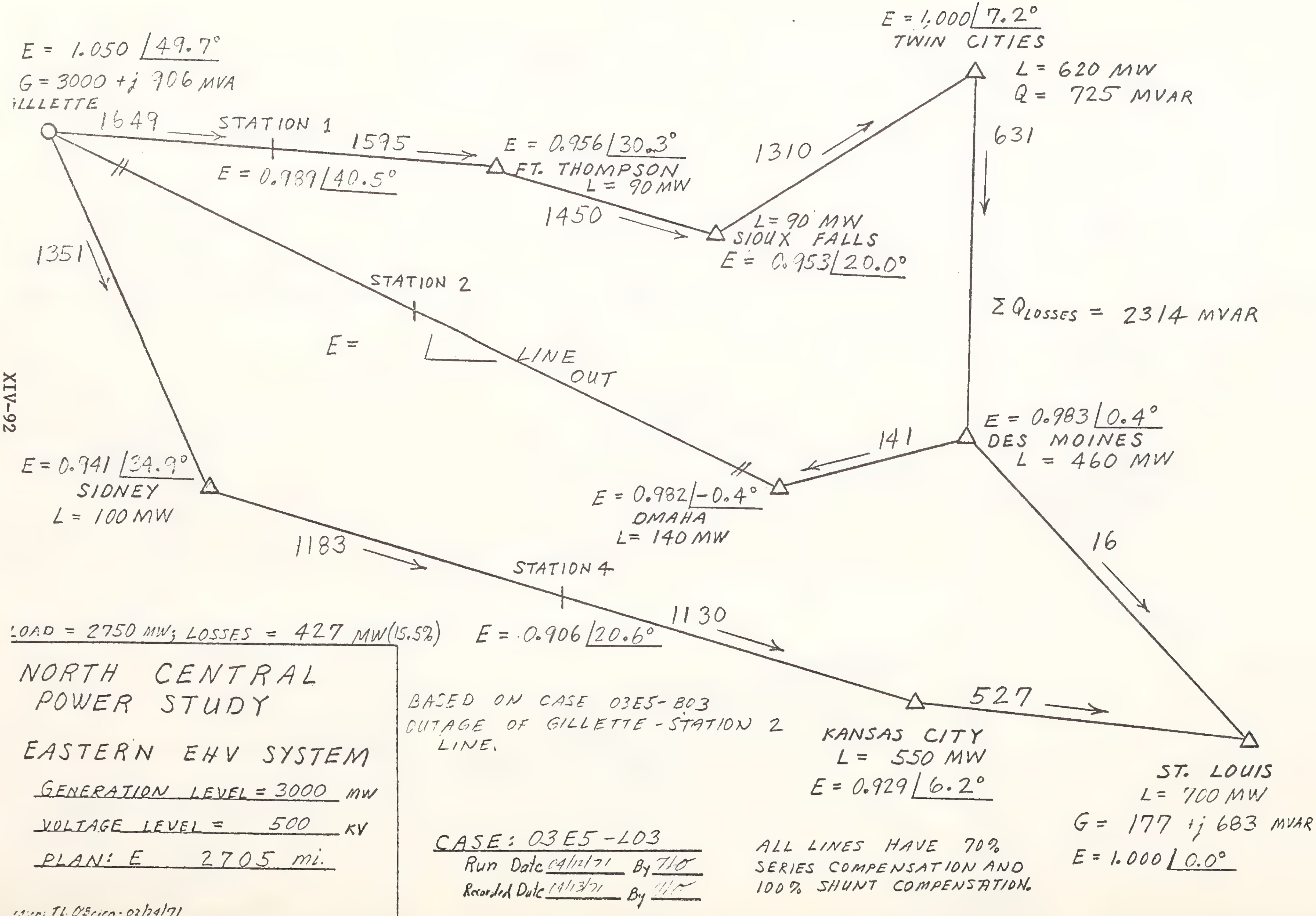


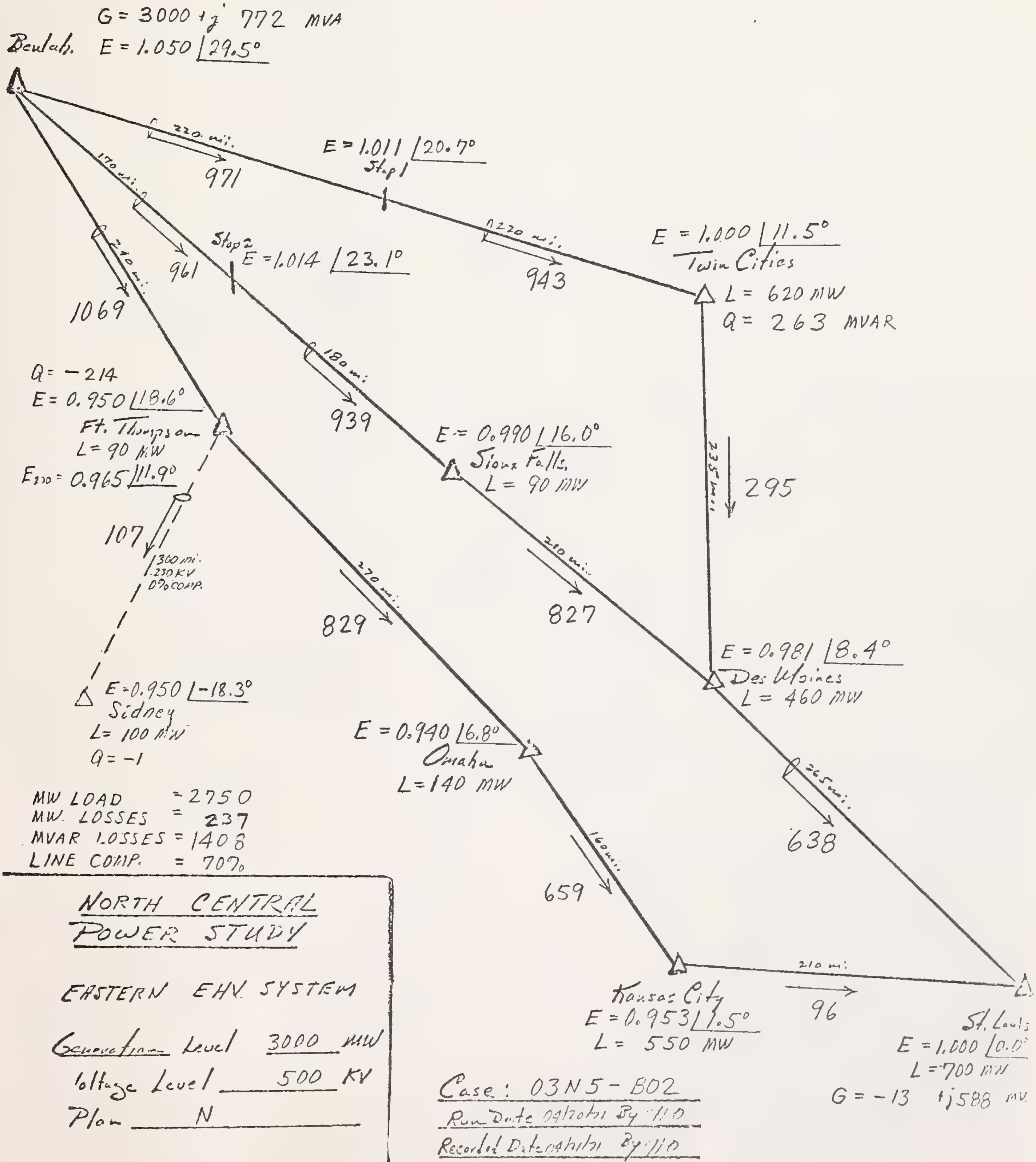
E = 1.050 32.6°
G = 3000 + j 577 MVA
GILLETTE
STATION 1
1020
E = 1.021 26.8°
E = 1.001 20.7°
FT. THOMPSON
L = 90 MW
909
801
L = 90 MW
SIOUX FALLS
E = 0.993 14.8°
E = 1.000 7.5°
TWIN CITIES
L = 620 MW
Q = 353 MVAR
161
ΣQ LOSSES = 1436 MVAR
960
STATION 2
E = 0.994 21.3°
927
E = 0.975 10.2°
OMAHA
L = 140 MW
753
E = 0.978 5.9°
DES MOINES
L = 460 MW
442
SIDNEY
L = 100 MW
864
STATION 4
E = 0.963 12.5°
838
262
KANSAS CITY
L = 550 MW
E = 0.766 3.0°
ST. LOUIS
L = 700 MW
G = 9 + j 506 MVAR
E = 1.000 0.0°
LOAD = 2750 MW; LOSSES = 259 MW (9.4%)
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
GENERATION LEVEL = 3000 MW
VOLTAGE LEVEL = 500 KV
PLAN: E 2705 mi.
CASE: 03E5- B03
Run Date
By
Recorded Date
By
ALL LINES HAVE 70%
SERIES COMPENSATION AND
100% SHUNT COMPENSATION.



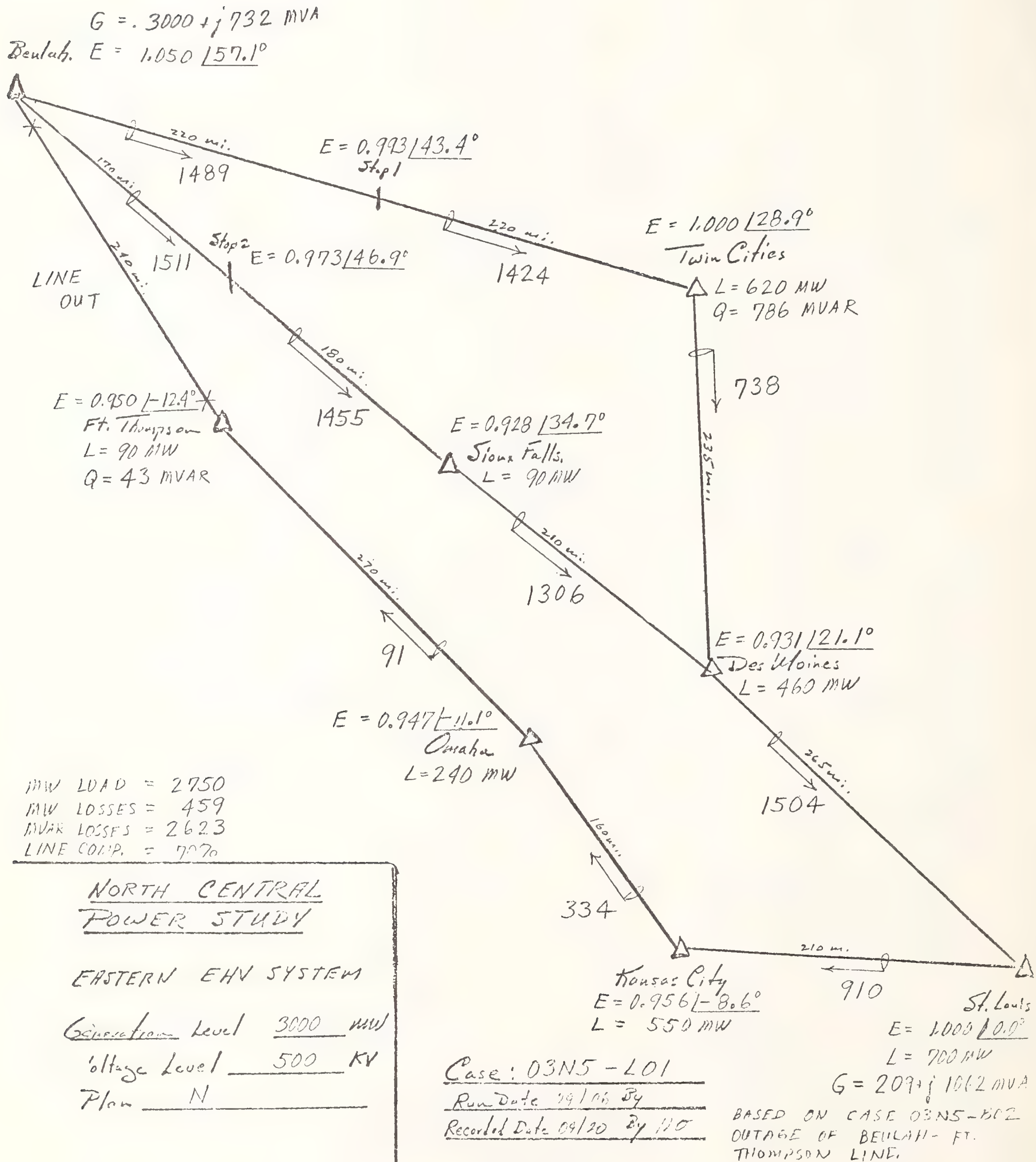
E = 1.050 ∠51.0°
G = 3000 + j 1209 MVA
GILLETTE
LINE OUT
STATION 1
E =
E = 0.997 ∠-12.9°
FT. THOMPSON
L = 90 MW
E = 1.000 ∠-10.7°
TWIN CITIES
L = 620 MW
Q = 622 MVAR
1627
1373
90
L = 90 MW
SIOUX FALLS
E = 0.998 ∠-12.3°
837
STATION 2
ΣQ LOSSES = 2782 MVAR
E = 0.906 ∠31.5°
1520
E = 0.928 ∠-0.2°
DES MOINES
L = 460 MW
1274
E = 0.937 ∠35.8°
SIDNEY
L = 100 MW
1203
E = 0.893 ∠8.5°
OMAHA
L = 140 MW
STATION 4
1147
69
LOAD = 2750 MW; LOSSES = 497 MW (18.1%)
E = 0.901 ∠21.2°
NORTH CENTRAL
POWER STUDY
BASED ON CASE 03E5-B03
OUTAGE OF GILLETTE - STATION 1
LINE.
541
KANSAS CITY
L = 550 MW
E = 0.925 ∠6.4°
ST. LOUIS
L = 700 MW
G = 247 + j 951 MVAR
E = 1.000 ∠0.0°
EASTERN EHV SYSTEM
GENERATION LEVEL = 3000 MW
VOLTAGE LEVEL = 500 KV
PLAN: E 2705 mi.
CASE: 03E5 - L01
Run Date 04/12/71 By
Recorded Date 04/13/71 By
ALL LINES HAVE 70%
SERIES COMPENSATION AND
100% SHUNT COMPENSATION.
T.L. O'Brien - 02/24/71

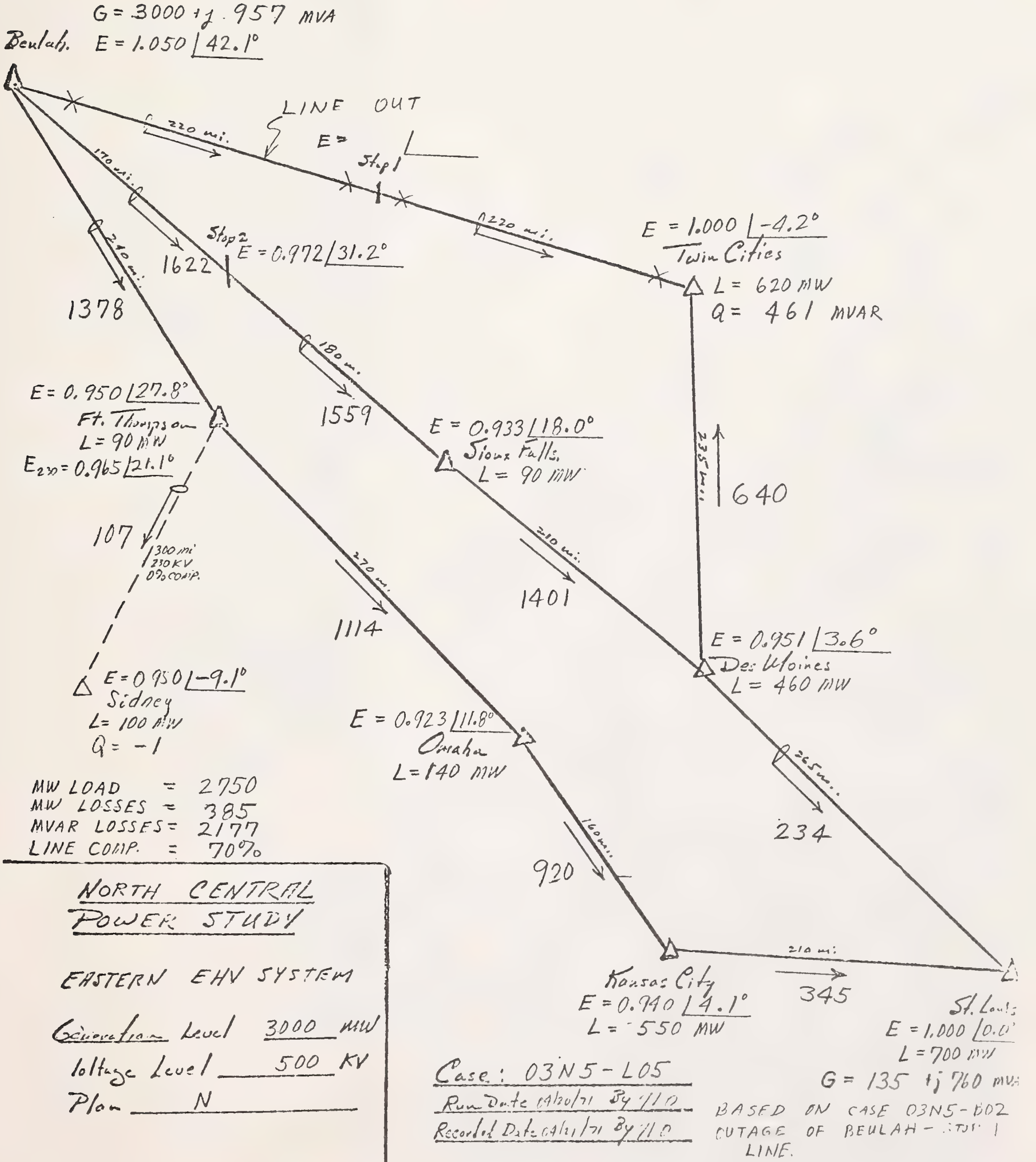

E = 1.050 ∠61.7°
G = 3000 + j 887 MVA
ILLETTE
1535
STATION 1
E = 0.976 ∠53.1°
1488
E = 0.966 ∠43.8°
FT. THOMPSON
L = 90 MW
1352
L = 90 MW
SIOUX FALLS
E = 0.963 ∠34.4°
1219
E = 1.000 ∠22.6°
TWIN CITIES
L = 620 MW
Q = 916 MVAR
549
Σ Q LOSSES = 2639 MVAR
1465
STATION 2
E = 0.928 ∠44.5°
1381
E = 0.908 ∠24.6°
OMAHA
L = 140 MW
1157
E = 0.930 ∠17.0°
DES MOINES
L = 460 MW
1200
ST. LOUIS
L = 700 MW
G = 234 + j 836 MVAR
E = 1.000 ∠0.0°
666
LINE OUT
E = 0.965 ∠-8.4°
SIDNEY
L = 100 MW
101
STATION 4
E = 0.968 ∠-7.3°
102
KANSAS CITY
L = 550 MW
E = 0.971 ∠-6.2°
ALL LINES HAVE 70% SERIES COMPENSATION AND 100% SHUNT COMPENSATION.
LOAD = 2750 MW; LOSSES = 484 MW (17.6%)
BASED ON CASE 03E5-B03 OUTAGE OF GILLETTE - SIDNEY LINE.
CASE: 03E5-L02
Run Date
By
Recorded Date
By
NORTH CENTRAL POWER STUDY
EASTERN EHV SYSTEM
GENERATION LEVEL = 3000 MW
VOLTAGE LEVEL = 500 KV
PLAN: E 2705 mi.

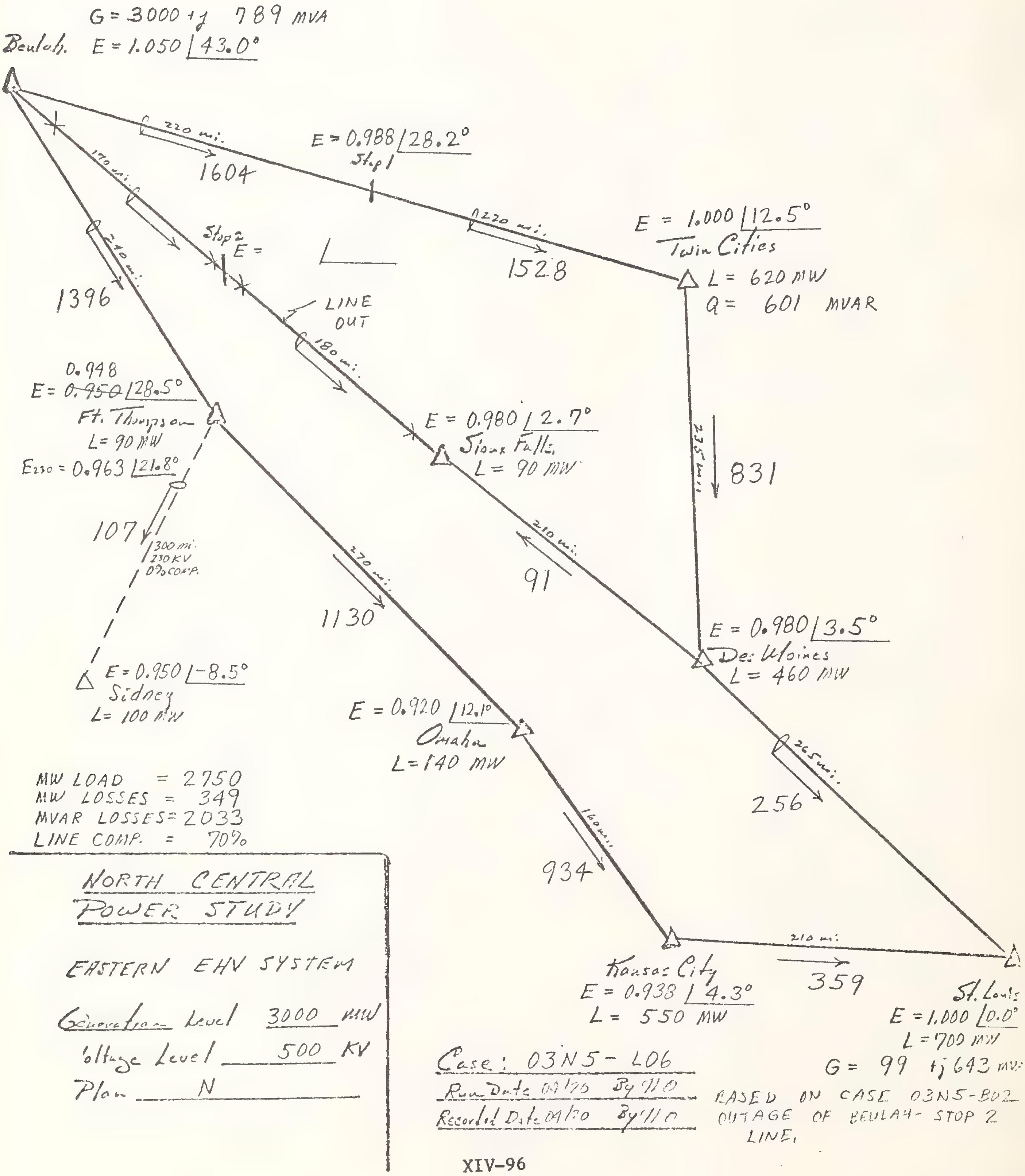

E = 1.050 ∠49.7°
G = 3000 + j 906 MVA
ILLETTE
1649
STATION 1
1595
E = 0.989 ∠40.5°
E = 0.956 ∠30.3°
FT. THOMPSON
L = 90 MW
1450
L = 90 MW
SIOUX FALLS
E = 0.953 ∠20.0°
1310
E = 1.000 ∠7.2°
TWIN CITIES
L = 620 MW
Q = 725 MVAR
631
ΣQ LOSSES = 2314 MVAR
1351
STATION 2
E =
LINE OUT
E = 0.983 ∠0.4°
DES MOINES
L = 460 MW
141
E = 0.941 ∠34.9°
SIDNEY
L = 100 MW
E = 0.982 ∠-0.4°
OMAHA
L = 140 MW
16
1183
STATION 4
1130
LOAD = 2750 MW; LOSSES = 427 MW (15.5%)
E = 0.906 ∠20.6°
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
GENERATION LEVEL = 3000 MW
VOLTAGE LEVEL = 500 KV
PLAN: E 2705 mi.
BASED ON CASE 03E5-B03
OUTAGE OF GILLETTE - STATION 2
LINE.
527
KANSAS CITY
L = 550 MW
E = 0.929 ∠6.2°
ST. LOUIS
L = 700 MW
G = 177 + j 683 MVAR
E = 1.000 ∠0.0°
CASE: 03E5-L03
Run Date 04/12/71
Recorded Date 04/13/71
ALL LINES HAVE 70%
SERIES COMPENSATION AND
100% SHUNT COMPENSATION.



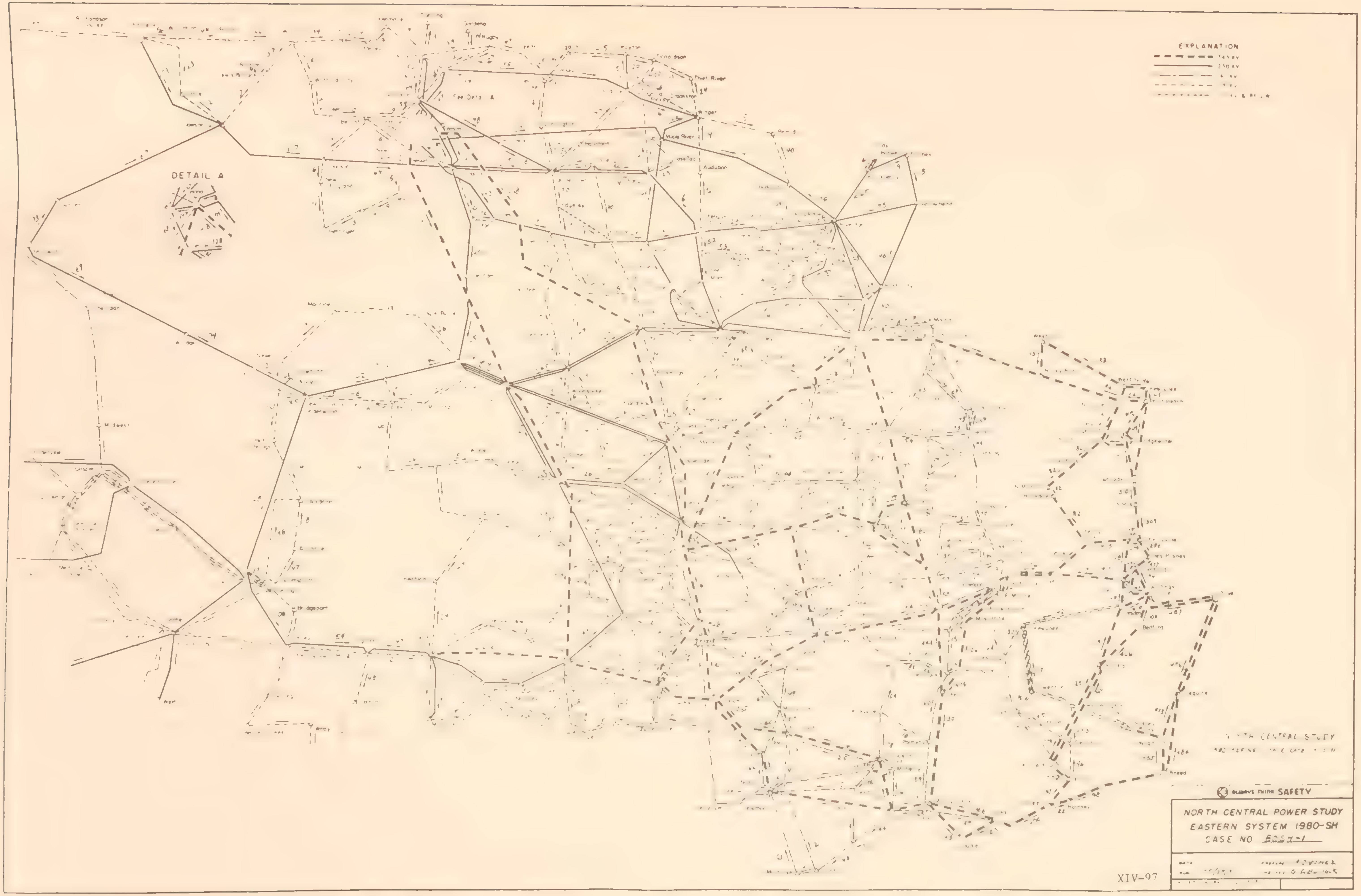
G = 3000 + j 772 MVA
Beulah E = 1.050 ∠29.5°
220 mi.
971
E = 1.011 ∠20.7°
Step 1
170 mi.
961
Step 2
E = 1.014 ∠23.1°
220 mi.
943
E = 1.000 ∠11.5°
Twin Cities
L = 620 MW
Q = 263 MVAR
210 mi.
1069
180 mi.
939
Q = −214
E = 0.950 ∠18.6°
Ft. Thompson
L = 90 MW
E230 = 0.965 ∠11.9°
E = 0.990 ∠16.0°
Sioux Falls
L = 90 MW
235 mi.
295
107
360 mi.
230 KV
0% COMP.
210 mi.
827
270 mi.
829
E = 0.981 ∠8.4°
Des Moines
L = 460 MW
E = 0.950 ∠−18.3°
Sidney
L = 100 MW
Q = −1
E = 0.940 ∠6.8°
Omaha
L = 140 MW
265 mi.
638
MW LOAD = 2750
MW LOSSES = 237
MVAR LOSSES = 1408
LINE COMP. = 70%
160 mi.
659
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
Generation Level 3000 MW
Voltage Level 500 KV
Plan N
210 mi.
96
Kansas City
E = 0.953 ∠1.5°
L = 550 MW
St. Louis
E = 1.000 ∠0.0°
L = 700 MW
G = −13 + j588 MVA
Case: 03N5 - B02
Run Date
Recorded Date

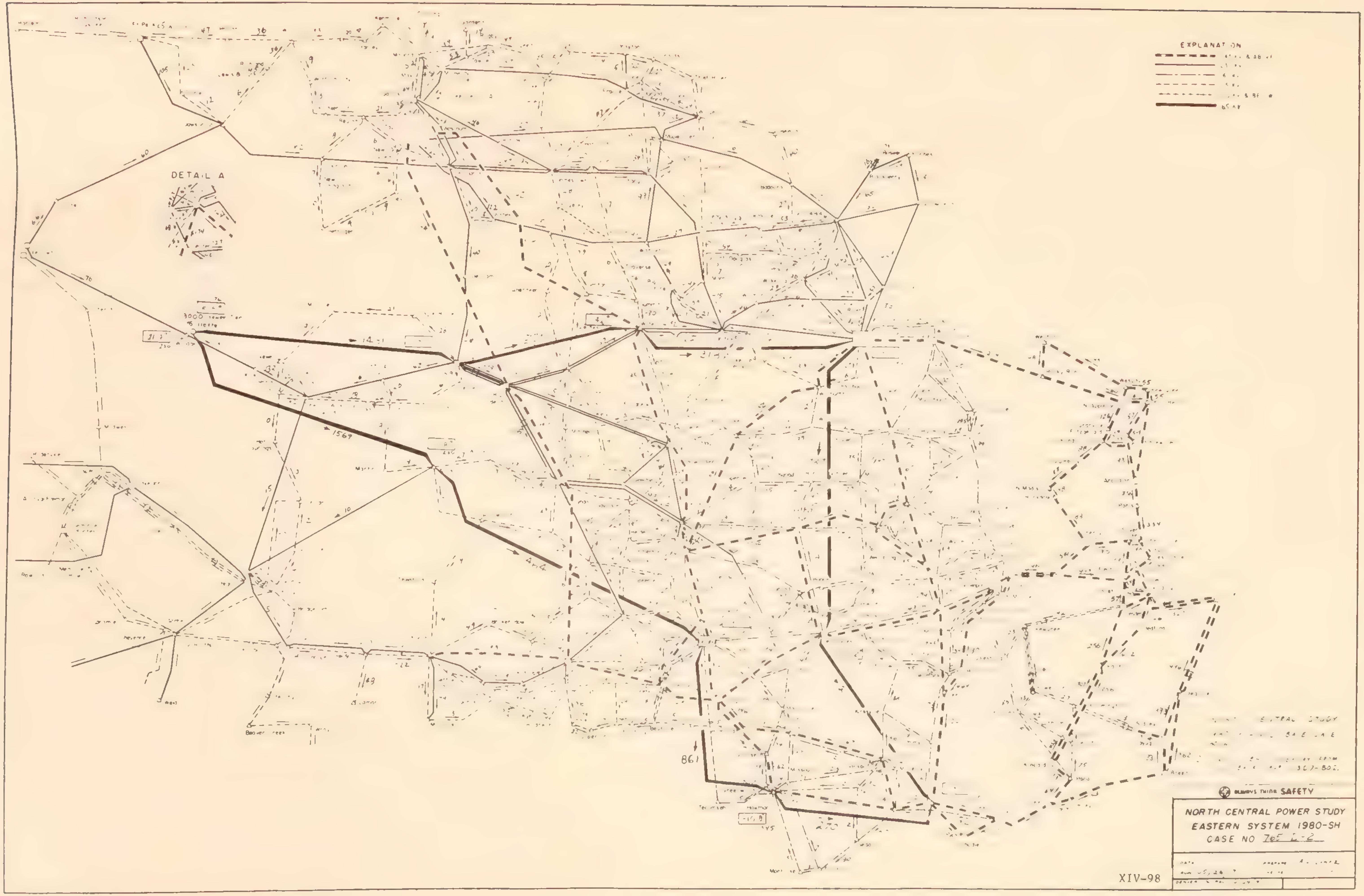

G = . 3000 + j 732 MVA
Beulah. E = 1.050 ∠57.1°
220 mi.
1489
E = 0.993 ∠43.4°
Step 1
170 mi.
1511
Stop 2
E = 0.973 ∠46.9°
220 mi.
1424
E = 1.000 ∠28.9°
Twin Cities
L = 620 MW
Q = 786 MVAR
LINE OUT
210 mi.
180 mi.
1455
738
235 mi.
E = 0.950 ∠-12.4°
Ft. Thompson
L = 90 MW
Q = 43 MVAR
E = 0.928 ∠34.7°
Sioux Falls.
L = 90 MW
210 mi.
1306
270 mi.
91
E = 0.931 ∠21.1°
Des Moines
L = 460 MW
E = 0.947 ∠-11.1°
Omaha
L = 240 MW
265 mi.
1504
MW LOAD = 2750
MW LOSSES = 459
MVAR LOSSES = 2623
LINE COMP. = 70%
160 mi.
334
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
Generation Level 3000 MW
Voltage Level 500 KV
Plan N
210 mi.
910
Kansas City
E = 0.956 ∠-8.6°
L = 550 MW
St. Louis
E = 1.000 ∠0.0°
L = 700 MW
G = 209 + j 1062 MVA
Case: 03N5 - L01
Run Date 09/06 By
Recorded Date 09/20 By HO
BASED ON CASE 03N5-B02
OUTAGE OF BEULAH - FT. THOMPSON LINE.

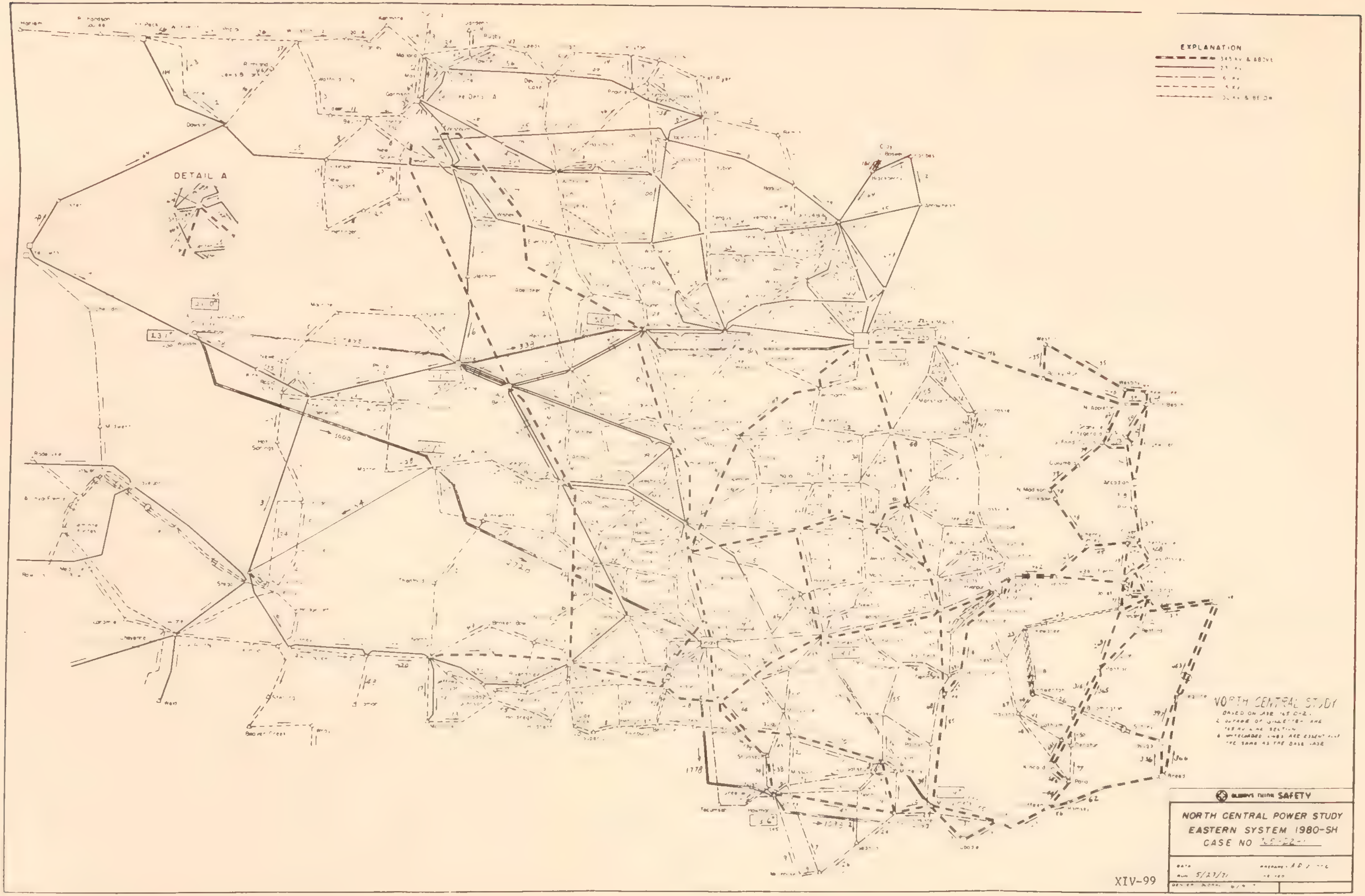

G = 3000 + j 957 MVA
Beulah. E = 1.050 ∠42.1°
LINE OUT
E =
Stop 1
220 mi.
220 mi.
170 mi.
240 mi.
1622
1378
Stop 2
E = 0.972 ∠31.2°
E = 1.000 ∠-4.2°
Twin Cities
L = 620 MW
Q = 461 MVAR
180 mi.
1559
E = 0.950 ∠27.8°
Ft. Thompson
L = 90 MW
E230 = 0.965 ∠21.1°
E = 0.933 ∠18.0°
Sioux Falls.
L = 90 MW
235 mi.
640
107
300 mi
230 KV
0% COMP.
270 mi.
210 mi.
1401
1114
E = 0.951 ∠3.6°
Des Moines
L = 460 MW
E = 0.950 ∠-9.1°
Sidney
L = 100 MW
Q = -1
E = 0.923 ∠11.8°
Omaha
L = 140 MW
265 mi.
MW LOAD = 2750
MW LOSSES = 385
MVAR LOSSES = 2177
LINE COMP. = 70%
234
160 mi.
920
NORTH CENTRAL
POWER STUDY
EASTERN EHV SYSTEM
Generation Level 3000 MW
Voltage Level 500 KV
Plan N
210 mi.
345
Kansas City
E = 0.940 ∠4.1°
L = 550 MW
St. Louis
E = 1.000 ∠0.0°
L = 700 MW
G = 135 + j 760 MVA
Case: 03N5-L05
BASED ON CASE 03N5-B02
OUTAGE OF BEULAH - STOP 1
LINE.

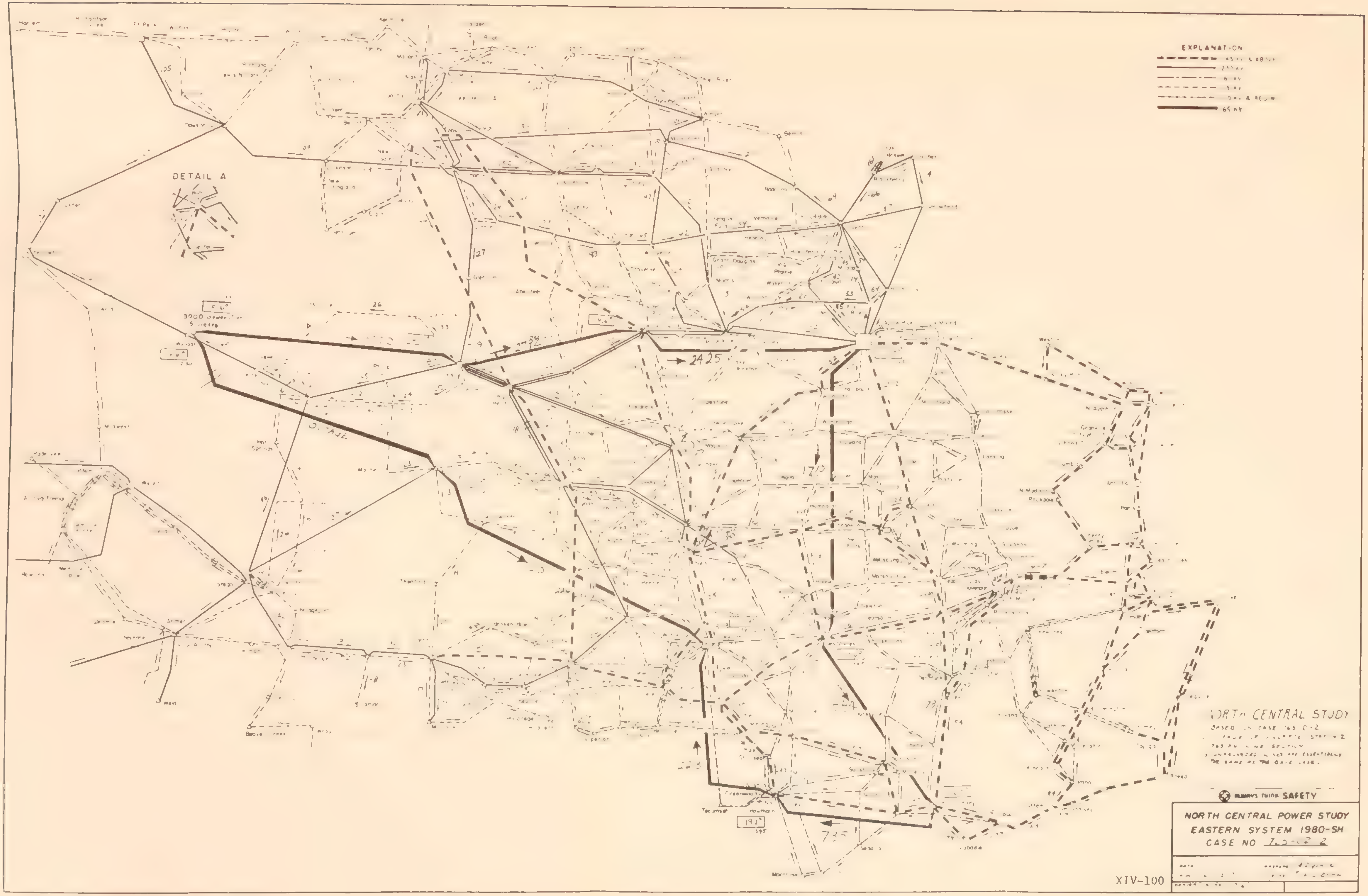


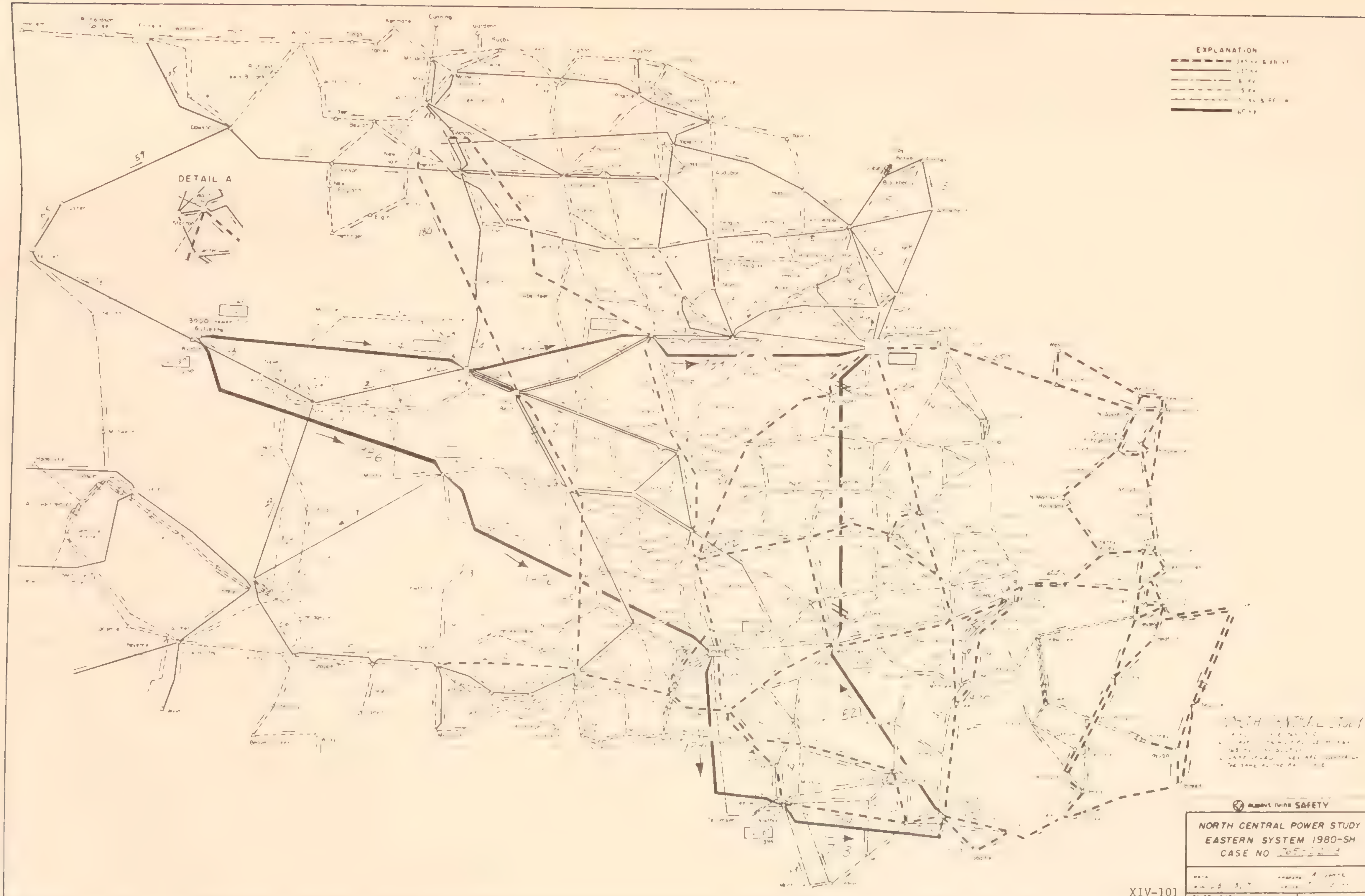
G = 3000 + j 789 MVA
Beulah E = 1.050 ∠43.0°
220 mi.
1604
E = 0.988 ∠28.2°
Stop 1
220 mi.
1528
E = 1.000 ∠12.5°
Twin Cities
L = 620 MW
Q = 601 MVAR
170 mi.
Stop 2
E =
LINE OUT
180 mi.
210 mi.
1396
0.948
E = ~~0.950~~ ∠28.5°
Ft. Thompson
L = 90 MW
E230 = 0.963 ∠21.8°
107
300 mi.
230 KV
0% COMP.
E = 0.950 ∠-8.5°
Sidney
L = 100 MW
E = 0.980 ∠2.7°
Sioux Falls
L = 90 MW
235 mi.
831
210 mi.
91
270 mi.
1130
E = 0.980 ∠3.5°
Des Moines
L = 460 MW
E = 0.920 ∠12.1°
Omaha
L = 140 MW
265 mi.
256
160 mi.
934
MW LOAD = 2750
MW LOSSES = 349
MVAR LOSSES = 2033
LINE COMP. = 70%
NORTH CENTRAL POWER STUDY
EASTERN EHV SYSTEM
Generation Level 3000 MW
Voltage Level 500 KV
Plan N
210 mi.
359
Kansas City
E = 0.938 ∠4.3°
L = 550 MW
St. Louis
E = 1.000 ∠0.0°
L = 700 MW
G = 99 + j 643 MVA
Case: 03N5-L06
BASED ON CASE 03N5-B02
OUTAGE OF BEULAH-STOP 2 LINE.

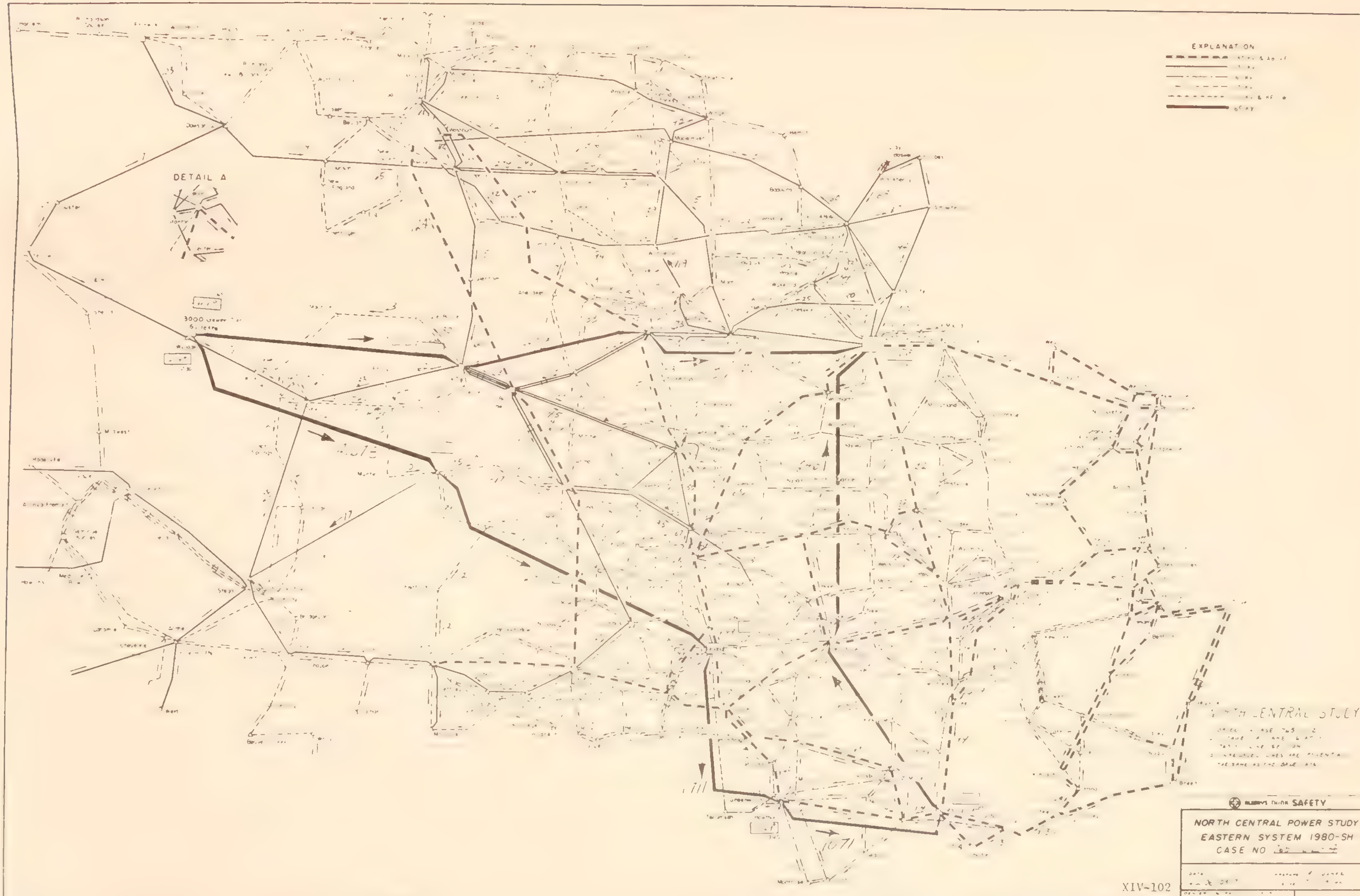

EXPLANATION
DETAIL A
Thief River
Audubon
SAFETY
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
CASE NO


EXPLANATION
DETAIL A
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
ALWAYS THINK SAFETY

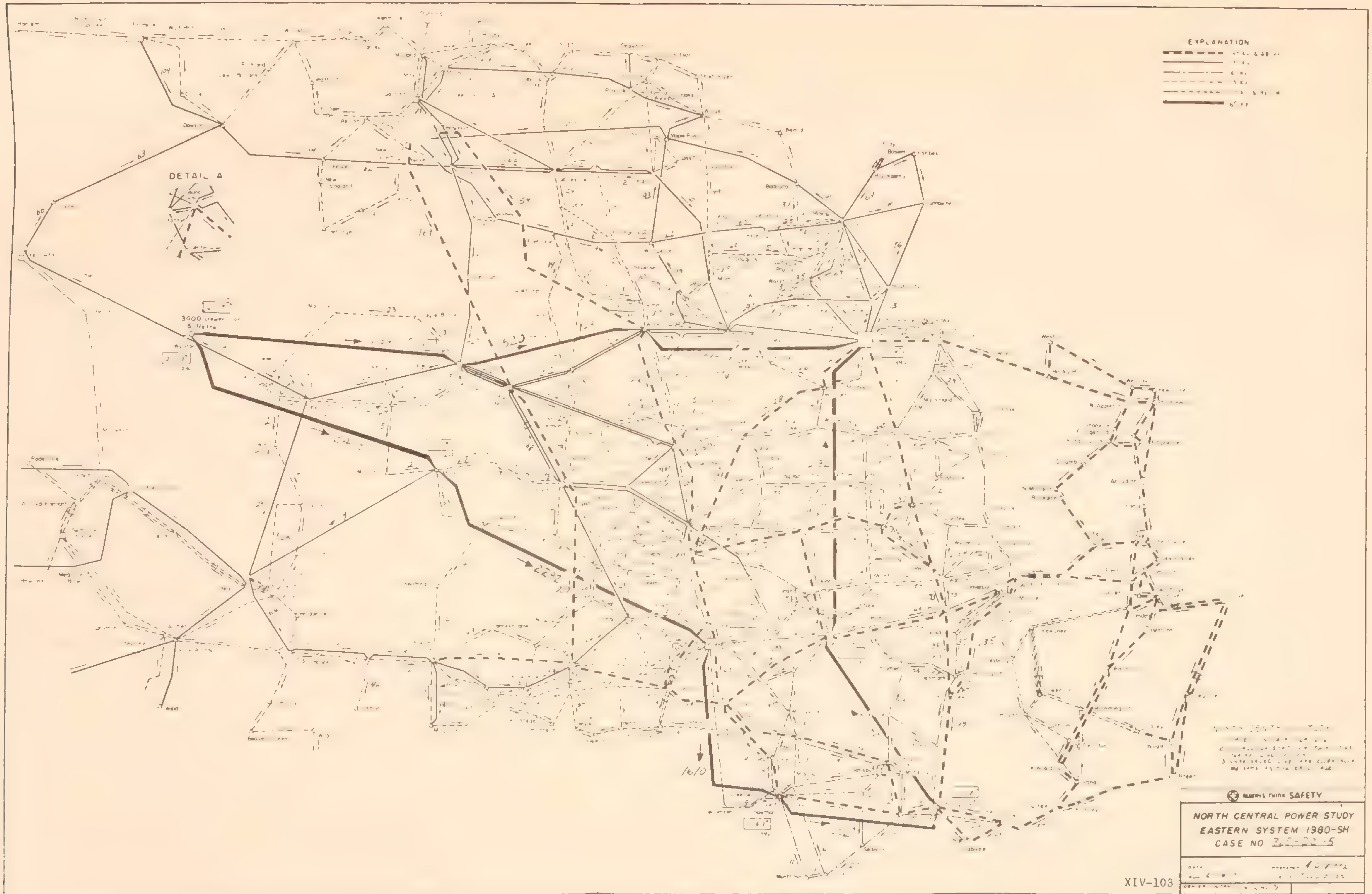

EXPLANATION
DETAIL A
VORTH CENTRAL STUDY
ALWAYS THINK SAFETY
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
CASE NO
5/27/71

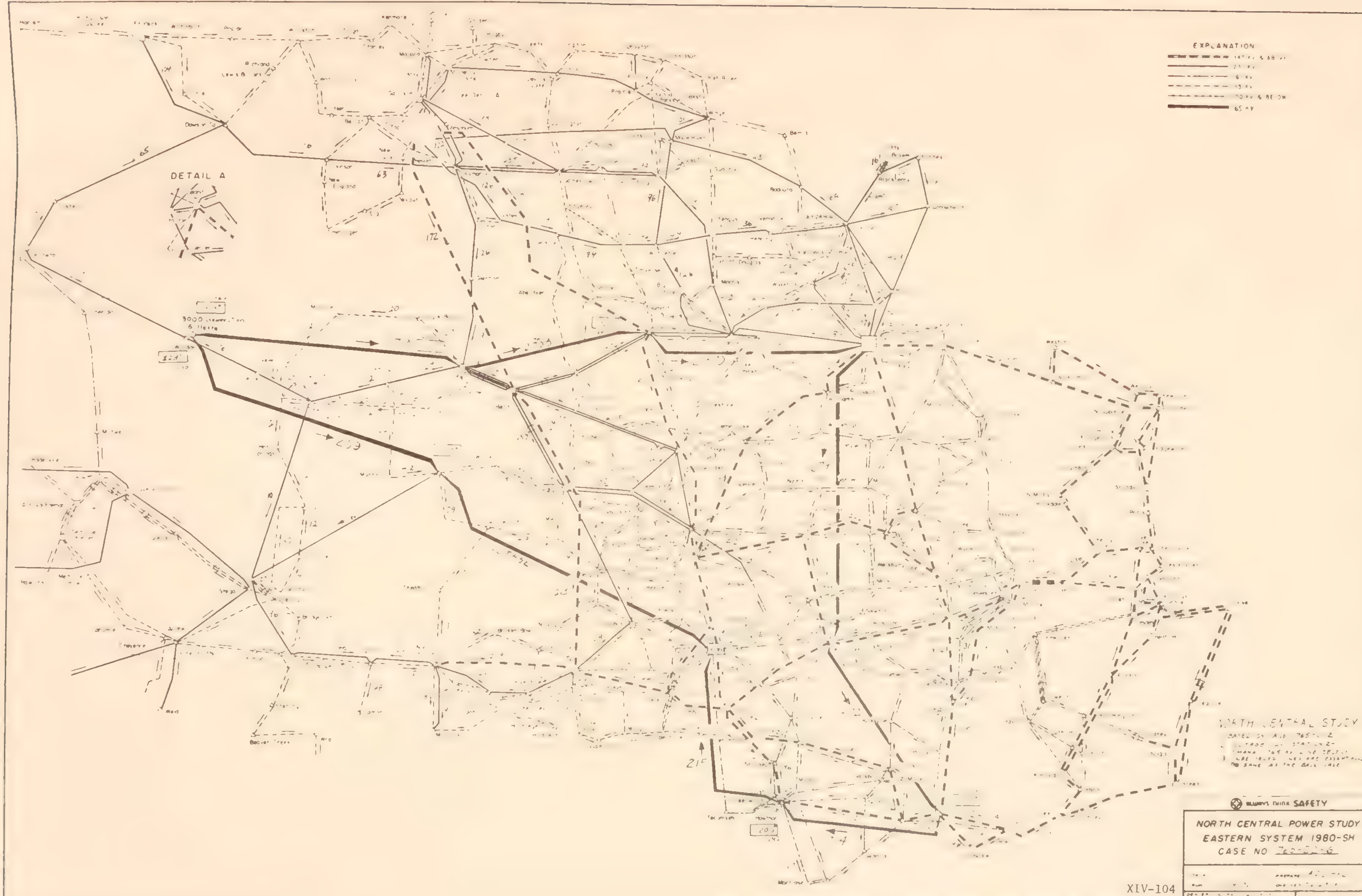

EXPLANATION
65 KV
DETAIL A
2425
1710
735
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
CASE NO
ALWAYS THINK SAFETY


EXPLANATION
DETAIL A
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
CASE NO
SAFETY

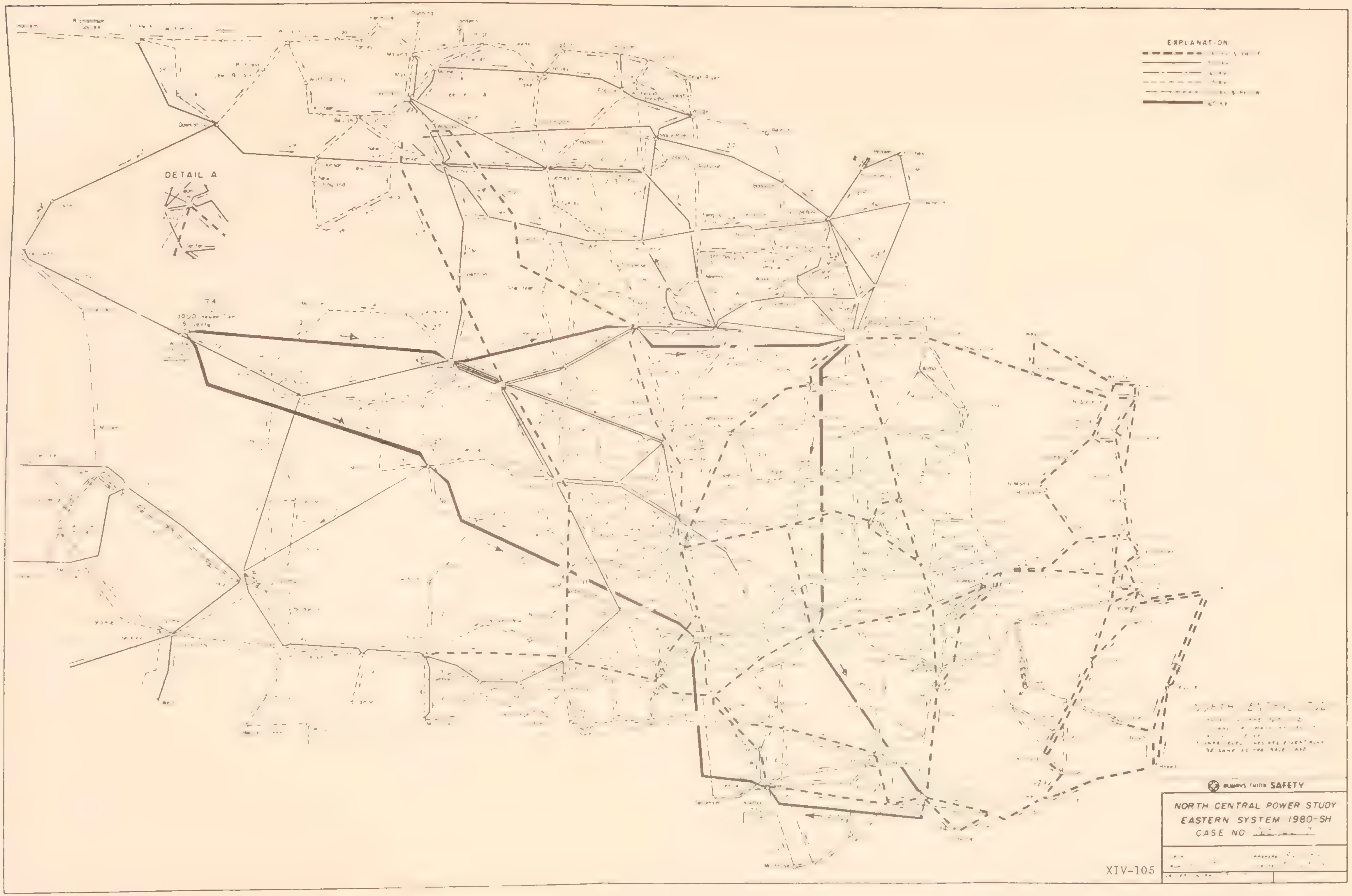


EXPLANATION
DETAIL A
3000 Megawatts
SAFETY
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
CASE NO

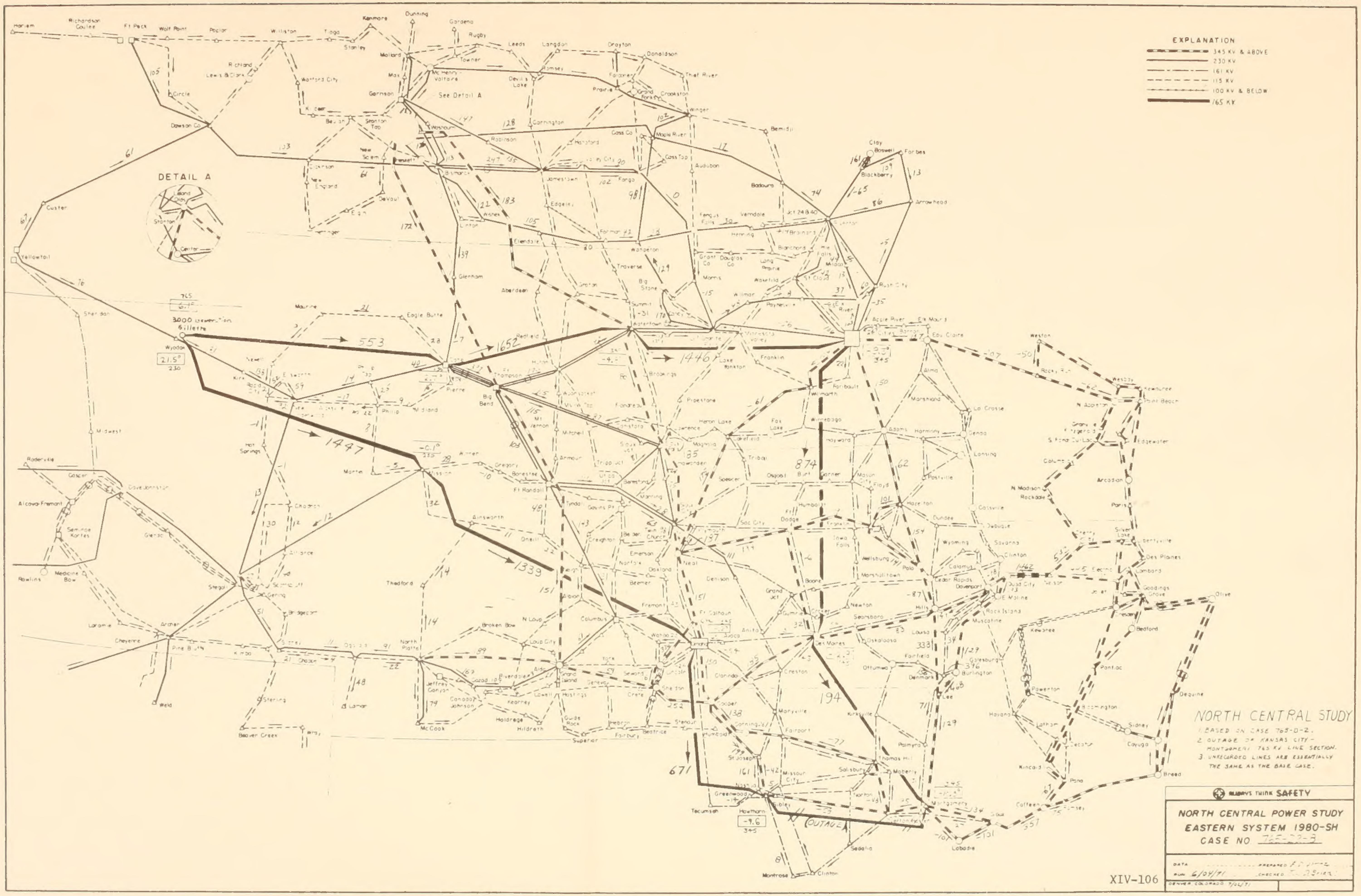

EXPLANATION
DETAIL A
3000 megawatts or 6 units
ALWAYS THINK SAFETY
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH



NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
CASE NO


EXPLANATION
DETAIL A
Always think SAFETY
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
CASE NO

GPO 838-328


EXPLANATION
345 KV & ABOVE
230 KV
161 KV
115 KV
100 KV & BELOW
765 KV
DETAIL A
See Detail A
NORTH CENTRAL STUDY
1. BASED ON CASE 765-D-2.
2. OUTAGE OF KANSAS CITY - MONTGOMERY 765 KV LINE SECTION.
3. UNRECORDED LINES ARE ESSENTIALLY THE SAME AS THE BASE CASE.
ALWAYS THINK SAFETY
NORTH CENTRAL POWER STUDY
EASTERN SYSTEM 1980-SH
CASE NO
RUN 6/04/71
DENVER, COLORADO 7/02/71
OUTAGE
Gillette
Watertown
Des Moines
Fargo
Bismarck
Omaha
Sioux City
Kansas City
St. Joseph
Burlington
Eau Claire
La Crosse
Lincoln
Cheyenne
Laramie
North Platte

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